Demand Response: Principles for Regulatory Guidance

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Preface

The Board of Directors of the Peak Load Management Alliance (PLMA) has reviewed several drafts of this document with the understanding that its review did not constitute endorsement of all the recommendations either personally or by their organization. However, there was agreement that this version (i.e., Version 1.0) made a positive contribution to the debate and the Board members in attendance voted unanimously in favor of the PLMA publishing this paper. It is recognized that additional information and learning about the role of demand response in energy markets will occur over time and as additional experiences are gained. The PLMA welcomes comments and encourages organizations and individuals to participate in discussions that will result in subsequent versions of this paper.

Acknowledgements

This policy paper developed under the active leadership of Mr. Ross Malme (Chair of the Peak Load Management Alliance and CEO of RETX) and Mr. Joel Gilbert (PLMA Vice-Chair and CEO of Apogee Interactive). Dr. Daniel Violette (PLMA Board Member and Principal, Summit Blue Consulting) served as the project leader and worked with Larry Barrett as a contributing author. Larry Barrett (President, Barrett Consulting Associates, Inc.) served as principal researcher, facilitator, and writer.

Many significant contributions came from PLMA Board members, as well as from outside contributors. An informal review committee included: Aaron Bridenbaugh, Price Response Load Coalition; Rick Berryman, New England ISO; Greg Bullington, Kansas City Power and Light; Angela Chuang, Alstom ESCA Corporation; Ed Cooley, TXU Energy Services; Don Gilligan, Predicate LLC; Steve Fernands, Customized Energy Solutions; Dal Fransden, DJF Consulting; Don Fuller, California ISO; Rick Hornby, Tabors, Caramanis & Associates; Leland Keller, E Source; David Lawrence, New York ISO; Joe Leccese, Comverge Technologies; Paul McCurley, New England, ISO; Sarah McKinley, E Cubed; Jay Morrison, National Rural Electric Cooperative Association; Bernie Neenan, Neenan Associates; Glen Perez, California ISO; Steve Rosenstock, Edison Electric Institute; Karen Sawyer, National Rural Electric Cooperative Association; William Schofield, Customized Energy Solutions; Chris Siebens, First Energy Services; William Smith, EPRI; Andrew Spahn, National Association of Regulatory Utility Commissioners; Keturah Stephens, e-Acumen; Steve Sunderhauf, Pepco; Rich Tabin, RETX; Bill Uhr, UHR Technologies; Paul Wattles, Good Company Associates; Steve Whitley, New England ISO; and Christopher Young, E Cubed.

Finally, Ms. Janice Pagel deserves credit for her final editing and formatting work on the document. These contributions are often given too little recognition.

More information about these contributors and the PLMA can be found at – www.PeakLMA.com.

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Executive Summary

The purpose of this policy paper is to recommend principles for use by regulatory authorities and others to promote the most cost-effective use of demand response for energy management. Demand response in electricity is defined as load response called for by others and price response managed by end-use customers. Demand response is important to the continued development of wholesale and retail electricity markets. Competitive markets are based on the interaction of supply and demand in response to appropriate price signals. Failure to harness the ability of customers to change their demand in response to prices reduces overall market efficiency, particularly given the volatility of electricity prices.

It is important that regulatory agencies at both the federal and state levels support policies to balance demand response initiatives in step with the increased incentives that open wholesale markets offer to supply-side developers. This balance is needed to provide consumers with appropriate choices and create efficient markets where price volatility is addressed and mitigated, in part, by demand response.

The benefits of demand response are many, including:

- system reliability,
- cost reduction,
- market efficiency,
- risk management,
- environmental,
- customer service, and
- market power mitigation.

The benefits of demand response exceed costs by nearly ten to one according to recent analyses. National benefits of time-sensitive pricing alone could be $15 billion.[1] Demand response could contribute over 45,000 MW in additional resources toward reducing peak electricity demand nationally.[2] The value of demand response is expected to increase over the long term based on forecasted trends in transmission and generation capacity.

To achieve these benefits, more regulatory guidance is essential. Principles and actions on which regulatory guidance and policy might be based are listed below and discussed more fully in the main report.

P1 — Customer Participation: Demand response programs should be designed that foster participation by customers of all types and sizes.

P2 — Equal Treatment: Demand response resources should compete on an equal footing with generators in wholesale markets .

[1] McKinsey and Company, "The Benefits of Demand-Side Management and Dynamic Pricing Programs," May 1, 2001, p. 2.
[2] EPRI, "The Western States Power Crisis: Imperatives and Opportunities," June 25, 2001, p. 24.

P3 — Robust Markets: Encourage numerous participant relationships.

P4 — Flexible Metering: Metering arrangements between customers and their counterparties should be allowed under mutually acceptable terms.

P5 — Timely Reconciliation and Settlements: Market operators of demand response have an obligation to provide timely feedback of demand response performance and financial compensation.

P6 — Fair Value: Demand response participants should receive fair value.

P7 — Multiple Program Participation: Customers should be permitted to participate in both economic and reliability markets.

P8 — Agreements for Regulatory Information Only: Customer agreements should be confidential and subject to streamlined regulatory review.

P9 — Coordinated Regulatory Review and Oversight: Regulators that have jurisdiction over demand response programs should work cooperatively to remove barriers to implementation.

Based on these principles, recommended actions include the following:

A1 — Stimulate better reporting on demand response resources.

A2 — Establish specific goals for demand response

A3 — Allow fair cost recovery for demand response.

A4 — Design demand response into markets at the outset to provide greater value.

A5 — Improve standardization of interconnection rules.

A6 — Re-evaluate environmental rules to accommodate demand response resources.

A7 — Appropriately phase out price caps to encourage demand response.

A8 — Establish tariffs based on costs, including costs associated with managing risk.

A9 — Make decisions on metering timely with fair information ownership.

In summary, demand response offers great potential throughout the country to help meet electricity needs reliably and efficiently. It is crucial for regulatory officials to enable and encourage wholesale and retail markets to operate in ways that afford customers more choices through demand response.

1.0 Introduction and Purpose

The purpose of this policy paper is to recommend principles for use by regulatory authorities and others to encourage the most cost effective use of demand response for energy management. Demand response in electricity is defined as load response called for by others and price response managed by end-use customers. Load response includes direct load control of equipment (e.g., air conditioners), partial or curtailable load reductions, and complete load interruptions. Utilities that may call for load response include independent system operators (ISOs), load serving entities (LSEs), and utility distribution companies (UDCs). Price response includes real-time pricing, dynamic pricing, coincident peak pricing, time-of-use rates and demand bidding or buyback programs, collectively referred to as price-responsive load. These programs are discussed more in Appendix A.

Demand response is important to the continued development of wholesale and retail electricity markets. Competitive markets are based on the interaction of supply and demand in response to price signals. Failure to harness the ability of customers to change their demand in response to prices reduces overall market efficiency, which is especially important, given the volatility of wholesale electricity prices.

Barriers to demand response are inherent in the transition to more efficient electric markets and stem from a history of administered pricing in the electric industry, which still persists in most all retail markets. This history, and uncertainties in the development of electric markets, discourages investment in the infrastructure required to support appropriate demand response. As a result, the price elasticity of demand has probably decreased in recent years in states that have restructured their retail markets. This is due to the removal of time-of-use rates and other traditional utility load response programs. Moreover, regulated distribution utilities, uncertain about their future role in retail commodity markets, have deferred investments in advanced metering and information systems. These systems would provide price information to customers and record their hourly responses. Also, standard offers in states with retail choice have become even less flexible and more unfriendly to price response.

As a result, it is important that regulatory agencies at both the federal and state levels support policies to balance market access for demand response resources in step with the increased incentives that open markets provide to supply-side developers. This balance is needed to provide consumers with appropriate choices and to create efficient markets.

This is a long-term proposition. Electricity markets that incorporate economic demand response capability will contribute to the appropriate long-run development of efficient resource investments on both the demand and supply sides.

This paper discusses driving factors that make demand response a necessary component of future electric markets. It identifies points of leverage where regulatory agencies can stimulate economic demand response opportunities. The most appropriate transition path to markets where demand response is a viable option may be uncertain and subject to debate; however, it seems clear that steps need to be taken to move toward this objective. Accordingly, this paper offers a set of principles to that can be used to guide the effort.

The Peak Load Management Alliance (PLMA) intends for this paper to be educational, which requires presenting a balanced discussion of a range of views. The PLMA is a not-for-profit corporation whose mission is to develop, demonstrate, and evaluate methods for reducing peak electrical demand. Members include leading companies in electric generation, retail energy services, load aggregation, power exchange, demand response equipment, metering, grid management, market management, and information systems.

2.0 Benefits of Demand Response

Peak load management or demand response occurs when customers reduce or shift electricity use in response signals or to programs specifically designed to induce such actions. Demand response also occurs when distributed resources are dispatched by end-use customers for reliability or economy reasons. Demand response serves as a complement to energy efficiency efforts that reduce overall energy use.

Seven categories of benefits may be distinguished:

- **System Reliability.** Customer demand management can enhance reliability of the electric system by providing reductions in use during emergency conditions. EPRI has estimated that "Power interruptions and inadequate power quality already cause economic losses to the nation conservatively estimated at more than $100 billion a year."[3] Demand response can reduce those interruptions and reductions in quality.
- **Cost Reduction.** A key driver for demand management is cost avoidance and reduction. Demand response can permit LSEs and customers to avoid incurring costs for generation, transmission and distribution, including capacity costs, line losses, and congestion charges. Demand response can also save all customers money indirectly by reducing wholesale market prices and mitigating price volatility.
- **Market Efficiency.** When customers receive price signals and incentives, usage becomes more aligned with costs. To the extent customers alter behavior and reduce or shift on-peak usage and costs to off-peak periods, the result is more efficient use of the electric system. One study concluded that "… a 2.5% reduction in electricity demand statewide could reduce wholesale spot prices in California by as much as 24%; a 10% reduction in demand might slash wholesale price spikes by half."[4]
- **Risk Management.** Providers of retail energy purchase power in wholesale markets where prices can vary dramatically from day to day, and hour to hour. They can use demand response to substantially reduce their risk and their customers' risk in the market. Moreover, where retail markets are competitive, price guarantees provide substantial value to certain customers. Efficient markets are characterized, in part, by the ability to provide risk

[3] EPRI, "Technology Action Plan Addresses Western Power Crisis," *EPRI Journal*, Summer 2001, p. 5.
[4] Taylor Moore, "Energizing Customer Demand Response in California," *EPRI Journal*, Summer 2001, p. 8.

management products using all available economic tools. Retailers can hedge price risks by creating callable quantity options (i.e., contracts for demand response) and by creating appropriate price offers for those customers who are willing to face varying prices. In this manner, risk management products can be economically offered to those customers who most benefit from them. Overall, Demand response helps manage risks through ready availability, high reliability, refined modularity and rapid dispatchability.

- **Environmental.** Demand response can help reduce environmental burdens placed on the air, land and water. Electricity generation is responsible for a significant portion of those burdens, consuming one billion tons of coal annually and accounted for 90% of U.S. coal consumption in 2000.[5] Also, utility power plants consumed an estimated 3.1 quads or 13% of national natural gas usage in 2000.[6] Demand response can reduce the need to operate these plants. Demand response can also reduce or defer new plant development, and transmission and distribution capacity enhancements resulting in land use benefits for neighborhoods and countrysides.
- **Customer Service.** Many customers welcome opportunities to manage loads as a way to save on energy bills and for other reasons such as improving the environment. In this, the age of choice, demand response provides customers with greater control over their energy bills.
- **Market Power Mitigation.** Demand response programs help mitigate market power of traditional and new energy suppliers. This is especially the case when demand response can occur essentially coincident (i.e., in near real time) with tight supplies and/or transmission constraints that might lead to market power.

3.0 Assessing the Economic Value of Demand Response

It is important not only to recognize the many benefits of demand response but to quantify them. This section provides information on the benefits of demand response indicating that benefits are large and exceed the costs by several times.

3.1 Benefits Are Many Times the Costs for Demand Response for NYISO

Benefits have been recently estimated[7] for reducing demand in response to program requests in terms of:

- savings from reduced market prices,
- savings in costs of hedging due to reduced price volatility, and
- end-use customer savings due to fewer outages.

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[5] U.S. Department of Energy, Energy Information Administration, *Monthly Energy Review*, December 2001, p. 88.
[6] American Gas Association, "Balancing America's Energy Needs," *American Gas*, October 2001.
[7] This section is drawn from Neenan Associates, "NYISO PRL Program Evaluation: Executive Summary," New York Independent System Operator, January 15, 2002. www.nyiso.com. The numbers in this section come from the research underlying the referenced document.

The value of demand response is demonstrated in a recent analysis of the demand response programs of the New York Independent System Operator (NYISO) during the summer of 2001. This analysis shows benefits are many times greater than costs.

During the summer of 2001, some 292 customers participated in the Emergency Demand Response Program (EDRP) offered by the NYISO. Participants agreed to reduce loads upon a two-hour advance notice from the NYISO. Some 72% of the customers participated through their load serving entity (LSE), while 25% took advantage of offers from Curtailment Service Providers (CSP) and 3% contracted directly with the NYISO. Participants provided a maximum reduction of 425 MW. Program payments totaled $4.2 million for four event days.

One set of benefits is the reductions in market prices associated with activating the demand response programs. An analysis of location-based marginal pricing (LBMP) across five zones produces collateral benefits of up to $13 million for the four event days.

A second type of benefit is achieved by damping the variability in prices. There are substantial benefits in terms of reducing prices paid by LSEs to hedge their obligations, either through physical bilateral supply contracts or financial hedges. The estimate for the four load reductions in August 2001 alone totals $3.9 million.

A third benefit of the program is improved reliability. Customers gain through reduced outage costs. "Outage costs reflect the inconvenience associated with rescheduling activities, and damages suffered as a consequence of service curtailment….Given that the generally accepted value for outage costs is in the range of $2,500 – 5,000/MWH, the benefit cost/ratio is between 4.8 to one and 9.5 to one." Based on payments of $4.2 million, the implied reliability benefits are from $20 million to $40 million.

The costs and benefits discussed above were calculated for the emergency program with two hours notice. The NYISO offers a second demand response program. The day-ahead demand response program (DADRP) allows participants to bid in proposed load reductions. During the summer of 2001, 16 participants provided a maximum of 25 MW of coincident peak curtailments. Payments totaled over $200,000. Collateral benefits were estimated at $1.5 million and benefits in reduced hedging costs of $700,000.

Customers are allowed to participate in either or both programs. Loads offset by diesel-fueled backup generators are only allowed to participate in the emergency program. Gas fired units may participate in both emergency and day-ahead programs. Customer research showed general satisfaction with both programs, although participants prefer longer notification periods and higher payments. This underscores the fact that in program design, there are substantial tradeoffs between those features of value to the market and those of value to customers.

In summary, recent empirical research demonstrates demand response programs offer benefits many times their costs. Furthermore, benefits should increase as experience grows among existing and prospective participants.

3.2 Demand Response Could Have Saved $2.5 Billion in California in 2000

One type of demand response program relies on dynamic pricing, in which retail prices are set hourly based on hourly wholesale prices. Hourly retail pricing provides customers with opportunities to save in two ways. First, customers can avoid some, or all, of the risk management costs included in the tariffs regulated supply services. Second, consumers can modify usage in response to hourly prices to further reduce costs.

Traditional utility tariffs have been characterized by Hirst as encompassing two components: a) the electricity commodity, and b) the risk management or insurance component.[8] Historically, utilities and regulators factored in the insurance aspects implicitly by allowing generation capacity reserve margins to meet load fluctuations. Higher tariffs were permitted to allow for the higher costs associated with meeting peak loads due to fluctuations in economic activity, human behavior, weather, and other factors. In deregulated markets, such vertical bundling of commodity and risk management is difficult to sustain. With wholesale and retail competition, price fluctuations have increased causing greater risks that are not fully reflected in the cost basis for standard tariffs.

Dynamic hourly pricing allows customers to pay less, in part, since the risk or insurance costs are not included. One utility, Puget Sound Energy, estimates that by hedging costs it could readily quantify as being almost $3/MWh, or between 5% and 10% of generation costs. This estimate includes the costs of hedging against uncertain hydroelectric output, forced outages at thermal resources, and unusual temperatures (which affect electricity use of space heating).

The benefits of hourly pricing can be substantial as has been calculated for California. If hourly pricing had been in place for 20% of the retail load with an overall price elasticity of -0.25, electric bill savings would have been $220 million in California for 1999.

Savings would have been even greater for 2000, since prices in California were not only almost four times higher but also were much more volatile than in 1999. Dynamic hourly pricing would have saved consumers about $2.5 billion in 2000, or 12% of the statewide power bill (see Hirst, 2002).

While savings may not be as much in normal years, during abnormal years with high fuel prices, capacity shortages, and rapid load growth, dynamic pricing programs more than pay for themselves, like insurance. Implementing price-responsive demand programs requires policy makers to understand and accept the insurance aspects of dynamic pricing.

[8] This section is summarized from Eric Hirst, "The Financial and Physical Insurance Benefits of Price-Responsive Demand," January 2002. www.ehirst.com.

3.3 Benefits Nationally Could Be $15 Billion per Year

Dynamic pricing could save from $10 billion to $15 billion per year according to estimates of McKinsey & Company.[9] The estimate assumes dynamic pricing would be applied to all types of customers, including residential, commercial, and industrial facilities and that users on average would shift five to eight percent of their load from peak periods and curtail use another four to seven percent.

About 20% of the savings are attributed to such changes in usage. About 80% of the savings are attributed to lower wholesale peak prices.

McKinsey translates the savings into several other measures of benefits, including avoiding:

- $16 billion in peaking plants,
- 250 peaking plants at 125 MW each,
- 31,000 MW of peaking capacity,
- 680 billion cubic feet of natural gas, and
- 31,000 tons of nitrous oxide pollution per year.

4.0 Market Opportunities and Challenges

The opportunities for demand response are large but largely untapped. This section addresses key opportunities for and challenges to encouraging more demand response efforts.

4.1 Demand Response Opportunity of 45,000 MW

EPRI has estimated that demand response programs could reduce peak demand in the United States by an additional 45,000 MW or about 6% of peak baseline usage.[10] Yet, the market for demand response resources has barely been tapped. Facilities with computerized energy management systems have capabilities to manage lighting, air conditioning, and other energy uses. Production lines, agricultural processes, mining operations and other industrial applications can be shifted or reduced during peak periods.

Distributed resources serve a demand response role in many applications. For example, backup generators serving commercial and industrial facilities are estimated to have about 80,000 MW of capacity. While it is not necessary for the units to be synchronized with the grid, the large majority of this capability is not networked for parallel applications in demand response programs. However, it should be recognized that the large majority is diesel fuel fired as opposed to cleaner natural gas fired generation posing certain environmental issues.[11]

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[9] This section is based on McKinsey and Company, "The Benefits of Demand-Side Management and Dynamic Pricing Programs," May 1, 2001, p. 2.
[10] EPRI, "The Western States Power Crisis: Imperatives and Opportunities," June 25, 2001, p. 24.
[11] Leland Keller, E source, "Distributed Generation Aggregation, Dispatch and Control," 3rd Annual International Symposium on Distributed Energy Resources, November 2, 2001.

Utility Interest in Demand Response

Only about 27,000 MW of load, including backup generation, signed up for demand management programs in 1998 according to estimates by Edison Electric Institute based on U.S. Department of Energy surveys. About 50% of the load came from industrial customers, 25% from commercial and 25% from residential. While over 27,000 MW was available for demand management, only 13,000 or 49% was called upon during 1998.[12]

Utilities have recently shown an increased interest in demand response. A national survey of utility managers in 2001[13] showed that the top three reasons (see Table 1) for load management were:

- to reduce system peaks,
- to reduce high-cost energy, and
- to provide economic advantage for utility.

Table 1
Survey of Load Management Objectives
Ratings from 5 (most important) to 1 (least important)

Objective	Rating
Reduce system peaks	4.55
Reduce high-cost energy	4.23
Economic advantage for utility	3.78
Savings to consumer	3.55
Maintain customer comfort	3.42
Reduce capacity constraints	3.37
Do load shifting	3.20
Do our part to maintain system stability	3.18
Use for operation considerations	2.95
Reduce reserve requirements	2.95
Improve utility's system-wide efficiency	2.91

Notably, the bottom three reasons in 2001 were the top reasons in a similar survey four years earlier. In 1997, utility managers professed a lack of interest in demand management programs because:

- measures are not cost-effective,
- no incentive from wholesale rate structures, and
- excess capacity.

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[12] Steve Rosenstock, "The Future of Load Management," Edison Electric Institute, October 2000.
[13] Charles Newton, "From DSM to Demand Response," Electric Perspectives, November/December, 2001, pp. 36-37.

Capacity Drivers for Demand Response

Generating capacity reserve margins have dropped nationally from 21% in 1993 to 11% in 1999.[14] This has helped stimulate interest in demand response resources along with improved cost-effectiveness.[15]

Trends in reserve margins are mixed across reliability regions. For the eleven NERC reliability regions, NERC estimates that five will experience increased reserve margins and six decreased reserve margins in 2005 compared to 2002. Separate analysis by e-Acumen suggests at least one other region will experience reduced reserve margins. Table 2 presents forecasted reserve margins in 2002 and 2005 for each NERC region. It compares data filed with NERC (Regional Assessment) and e-Acumen's forecast (e-Acumen Assessment).[16]

Even where reserve margins may increase, demand response should be sought as a stabilizing resource to help mitigate the potential for boom and bust cycles that are possible in commodity markets such as electricity generation.

Transmission capacity limitations are another driver for using demand response resources. Transmission congestion is growing more prevalent. Costs of transmission congestion have been calculated as exceeding $800 million, and this is just for New England, New York, PJM and California for 2000.[17]

The transmission situation is forecast to deteriorate further. In its most recent reliability assessment, NERC projects little new transmission will be added during the next decade. As a result, NERC expects transmission limitations, and congestion will increase.[18]

Another study projects normalized transmission capacity to decline from 201 to 176 MW-miles/MW demand between 1999 and 2009.[19] "Maintaining a normalized capacity of 201 MW-miles/MW demand throughout the decade requires the construction of 26,600 GW-miles, compared with planned construction of only 6,200 GW-miles." If new construction maintained current levels of transmission capacity, investments would total an estimated $56 billion. This is equal to the current book value of transmission assets and about half of the $105 billion investment forecasted for new generation capacity over the ten-year period.

Clearly, demand response resources are necessary and valuable in the energy future to complement trends in both generation capacity and electricity transmission and distribution.

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[14] Edison Electric Institute, *EEI Statistical Yearbook*, 2001 Edition, Table 7, p. 14.

[15] Charles Newton, "From DSM to Demand Response," *Electric Perspectives*, November/December, 2001, p. 37.

[16] Provided by Keturah Stevens, e-Acumen, January 2002.

[17] R. Gales, J. Graves, and J. Clapp, *The Future of Electric Transmission in the United States: A Vision for Transmission as a Vibrant, Stand-Alone, For-Profit Business*, PA Consulting Group, January 2001.

[18] NERC, *"Reliability Assessment 2001-2010: The Reliability of Bulk Electric Systems in North America*, October 2001, www.nerc.com./publications.

[19] Information in this paragraph is drawn from Eric Hirst and Brendan Kirby, "Transmission Planning for a Restructuring U. S. Electricity Industry," June 2001, pp. 8 - 9.

Table 2
Reserve Margin Forecasts

	2002	2005
ECAR		
Regional Assessment[1]	14%	11%
e-Acumen Assessment[2]	25%	26%
ERCOT		
Regional Assessment[1]	40%	35%
e-Acumen Assessment[2]	47%	38%
FRCC		
Regional Assessment[1]	20%	23%
e-Acumen Assessment[2]	37%	22%
MAAC		
Regional Assessment[1]	26%	52%
e-Acumen Assessment[2]	22%	25%
MAIN		
Regional Assessment[1]	29%	27%
e-Acumen Assessment[2]	24%	27%
MAPP (United States Only)		
Regional Assessment[1]	20%	15%
e-Acumen Assessment[2]	42%	38%
New England		
Regional Assessment[1]	33%	26%
e-Acumen Assessment[2]	38%	36%
New York		
Regional Assessment[1]	17%	31%
e-Acumen Assessment[2]	22%	34%
SERC		
Regional Assessment[1]	13%	15%
e-Acumen Assessment[2]	23%	33%
SPP		
Regional Assessment[1]	17%	13%
e-Acumen Assessment[2]	**22%**	**25%**
WSCC		
Regional Assessment[1]	25%	46%
e-Acumen Assessment[2]	26%	44%

[1] (Net Demand – Net Capacity)/Net Demand. Based on 2001 NERC ES&D. New York based on the 2001 Load and Capability Report.[2]
Based on e-Acumen's Powerview™.

4.2 Market Challenges

Numerous challenges in both retail and wholesale markets frustrate the use of demand response resources.

Retail Market Challenges

The economic value to customers created by demand response that is not captured in market prices is a compelling argument for the continued development of demand response programs and infrastructure, even if there is a short-term boom in plant capacity. As a result of such pricing practices, there is significant underinvestment in demand response behavior and equipment.

The challenges to demand response appear in multiple ways. Barriers in retail markets may be classified as "…lack of information, lack of incentives, lack of enabling technologies, lack of functional wholesale market, lack of customer choice."[20]

Because of these barriers, it is a challenge to enroll both new and existing customers in these programs. For customers who have not participated in utility-sponsored programs in the past, in particular, demand-side resources require development time and consistent market rates from year to year, if the long-term benefits are to be attained.

For customers who have participated in utility-sponsored programs in the past, the transition to retail competition has often proven to be a step backward. Texas had over 3,000 MW involved in demand response programs prior to retail choice. Most of these resources appear to have been lost in the transition to retail choice. LSEs in Texas do not appear to be offering these programs, and providers of standard offers and default supply services have not been required to offer demand response programs. Another factor is that the regulatory rules are limiting for investor-owned distribution utilities: "Savings through load management programs, including interruptible rates, may not exceed 15% of the utility's total demand reduction goal."[21]

Part of the difficulty facing distribution utilities is that revenues are tied typically to throughput. This acts as a disincentive to demand response programs where less energy is sold, unless a non-bypassable surcharge is levied on the distribution of electricity.[22]

A further challenge at the distribution level is handling load disparities. Distribution systems may not peak at the same time as transmission systems. Congestion charges at the transmission level have proven effective. However at the distribution level, congestion charges require a separate program. Nevertheless, demand response programs including distributed generation can be effective in addressing local load situations.

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[20] EPRI, "The Western States Power Crisis: Imperatives and Opportunities," June 24, 2001, p. 29.
[21] Public Utility Commission of Texas, "Substantive Rules," 25.181 (g)(2)(I).
[22] EPRI, op. cit., June 24, 2001, p. 28.

Wholesale Market Challenges

An organizational challenge for those trying to participate in wholesale markets is that there is too much fragmentation among jurisdictions. It has been suggested there is a need to move wholesale markets to a regional level which will require cooperation among multiple jurisdictions.[23]

A specific challenge posed in existing wholesale markets is the use of price caps to reduce market volatility. For example, the FERC price cap in the WSCC reduces demand response interest and participation potential. If retained at the low level of $100/MWH, it may leave lasting damage to the energy markets in that region. With wholesale prices capped at that level, many load serving entities have little financial incentive to expand, or in some cases to even maintain, their demand response capabilities.

Mandating prices around $100/ MWH might be appropriate in monthly block forward markets, but should not be in place for day ahead or shorter-term markets. At the moment, the WSCC cap is being applied to the day ahead price for all 16 hours of the on peak period. That low price applied to individual hours reduces customer demand response activity.[24]

Such low prices present a challenge to justifying demand response programs. As it is, demand response programs are subject to heavy analysis before and after implementation to confirm their cost-effectiveness. By comparison, larger sums are spent on creating and operating ISOs with relatively little debate or analysis. Thus in terms of organizational planning and program development, more encouragement is warranted for demand response.

Another need is for better system planning. In the absence of more systematic planning, market participants are at greater risk, including generators, distributors, retailers and customers. Assuming ISOs are encouraged to take the lead in more comprehensive system planning, there are challenges in establishing baselines for information needs among market participants and in developing acceptable forecasting methods.[25]

5.0 Fundamentals of Demand Response

The most fundamental proposition for any product is that there must be a buyer and a seller. The question of who is the buyer or customer and who is the provider or seller can be quite confusing with demand response.

In the case of electricity, the ultimate buyer is normally the end-use customer, whether it is a residence, business, farm, or factory. In the case of demand response, the situation can be reversed. The energy end-user is selling callable demand reductions to another party, i.e., the power supplier might usefully be viewed as the buyer of demand response options.

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[23] Ibid., p. 28.
[24] Based on communications with Joel Gilbert, January 2002.
[25] EPRI, loc. cit., June 24, 2001.

The marketing channels between the energy producer and energy user can be quite complex. This is especially true in retail choice markets with unbundled electricity products as compared to monopoly markets with vertically bundled products. Table 3 summarizes many of the key parties and their activities in these more complex markets.[26]

The mix of these functions across regions varies based on different regulatory policies and market practices. Now that key market participants have been defined, it is useful to characterize the market functions in a general way.

5.1 Demand Response as a Product Offering

One way to view the structure for a demand response market is in textbook formula of the marketing mix.[27] There are, in most markets, five "Ps" to the marketing mix:

- Product: features, quality specifications, operations, services.
- Price: rates, payments, discounts, incentives, financing.
- Place: distribution, delivery, channels, installation, inventory.
- Promotion: information, education, advertising, sales.
- Public policy: rules, regulations, reporting.

Demand Response Product

Academics classify products as durable goods, nondurable goods, and services.[28] The demand response product or service may be defined in quantitative terms such as the amount of energy provided, power quality of energy provided, amount of energy reduction, and amount of capacity made available for reduction. Additional characteristics of demand response products include time of use, time of day ahead, day ahead or prospective use, timing of load reduction notification, timing of load reduction event, duration, frequency, and some combination of these characteristics. Such measures may be fixed or variable and mandatory or discretionary depending on the program.

The product may also be defined in terms of types of actions taken, types of technologies involved, types of measurement employed, and some combination of these factors. Usually an agreement or contract is necessary to define the terms and conditions for the demand response product, including pricing and delivery provisions.

Demand Response Pricing

Some prices are part and parcel of the product offering such as time-of-use rates, real-time pricing and coincident peak pricing. In these cases, the product is electricity defined by amount and time-of-use within specific pricing structures. The customer is the buyer.

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[26] For additional information see: California Independent System Operator, *Glossary of Terms,* 19 pp. www.caios.com.; and Electricity Reliability Region of Texas, *Glossary*, 32 pp. www.ercot.com

[27] Philip Kotler, Marketing Management, Prentice-Hall, Inc., 1984, p. 69.
[28] Ibid., p. 465.

Table 3
Key Electricity Market Entities and Activities

Entity	Activity
Customer	Purchases electricity for its own use. The end-use customer.
Load serving entity (LSE)	Provides electric service to customers and wholesale customers. LSEs include retail electric providers REPs.
Retail electric provider (REP)	Sells electricity to retail customers and does not own or operate generation assets.
Marketer	Takes title to electric power and resells to customers.
Aggregator	Handles planning, scheduling, accounting, billing and settlement from a portfolio of sellers (generators, purchases) and/or buyer (loads or sales).
Broker	An agent for others in negotiating contracts, purchases, or sales of electric energy or services without taking ownership.
Provider of last resort (POLR)	A retailer providing default service to customers.
Curtailment service provider (CSP)	Enrolls customers for demand response programs.
Utility distribution company (UDC)	Owns and maintains a distribution system for delivery of electricity. Also distribution service provider (DSP) and local distribution company (LDC).
Generator	Owns or controls a resource used for generating electricity.
Utility	Performs a mix of functions drawn from generation, transmission, distribution, curtailment service, and metering.
Independent system operator (ISO)	The FERC regulated control area operator of the transmission grid, including providing non-discriminatory access, managing congestion, maintaining the reliability and security of the grid, and providing billing and settlement services.
Regional transmission organization (RTO)	Association of transmission owners and users who act as a forum to report to the FERC on the implementation of open access to transmission systems. Also regional transmission group (RTG).
Power exchange (PX)	Conducts auctions to sell energy and loads, including demand response, not otherwise served by bilateral contracts.
Scheduling coordinator (SC)	Fulfills transactions and settlements between contracting parties for size in megawatts, start and end times, and other aspects involving the delivery and receipt of power.
Meter service provider	Installs and maintains metering equipment.
Meter data management agent	Reads and verifies meter information.

In the case of interruptible load programs, curtailable load programs and direct load control programs the pricing takes the form of credits, discounts, and other forms of direct or indirect payments. Here the customer is the seller receiving payment from the buyer for the callable portions of its load and only within the provisions of a larger supply agreement.

In the case of demand bidding or buyback programs, there is a need for a different pricing mechanism and a liquidity point. A liquidity point is the place where the value to the owner of the demand resource or the end-use customer is determined. Liquidity points can be established with an ISO or in bilateral energy markets. Prices are set based on the perception of value and risks. These usually are based on the buyer's perception of avoided or actual incremental costs, time periods, load reductions, and duration of demand response programs.

Another aspect is the pricing of transmission and distribution or wires services in a manner that better represents the long-term cost of adding or upgrading capacity. Rather than uniform pricing, separate pricing for both commodity and wires portions could better reflect their different marginal costs. Then demand response programs and time-sensitive pricing incorporating these higher incremental prices can enable shorter paybacks for investments in load management technologies. Depending on the market and the class of customer, the wires component can represent between 20% and 50% of the total energy bill.[29]

Demand Response Delivery

Another fundamental function in the mix is how the product is placed, that is, delivered or distributed. The end-use customer may deliver the demand resource directly to the ultimate buyer, namely the ISO. Or, the end-use customer may deliver through one or more market intermediaries, such as the LSE or the CSP. Thus the delivery channel may be from the end-use customer to a CSP and then to an ISO. All parties want assurance that what was sold is paid for according to appropriate terms and in a timely manner.

A key aspect is the ability for timely and uncontested measurement and verification. In some cases, the details of a program are stipulated or understood as part of prepaid incentives to customers (such as common in residential air conditioning or water heating load control products). In other cases, program designs allowing easy customer participation and simple protocols for performance measurement and verification are the key enabling (or disabling) mechanisms in a demand response.

Load response programs where customers reduce usage upon request can be viewed as an accounting transaction. This is because energy is not transferred from the customer to another party. On the other hand, load response may entail power transfers, especially when load response involves distributed generation.

Demand Response Marketing and Promotion

The roles for traditional, vertically integrated energy companies are in transition. In some states that have moved to retails choices, the "wires company" is no longer permitted to market and

[29] Communication from Bill Uhr, December 2001.

promote demand response. The grand plan was that innovation in the market would fill this need. That has not yet materialized. As a result, today's customers may not be aware of the benefits that they attain through exercising their ability to adjust use to better match the profile of electric prices. This may require external agents to fill the void (such as the ISO or RTO) to operate demand response programs. But even here, the need for information, marketing, and technical assistance to the customer is a daunting task.

Thus, marketing and promotion is an important function in the transition to open, competitive markets. There are multiple value propositions just as there are multiple demand response opportunities and market participants. For demand response to succeed, the many market participants must be educated and indeed sold on the values that can be achieved.

It is important to note that marketing is important for demand response programs even in markets not transitioning to retail choice. Monopoly electricity providers have been active in demand response in the past and should be in the future. Marketing to enroll customers for demand response is no less important in these markets as well.

Success in marketing is not only related to education and awareness of participants, but also program stability. If program designs change radically from year to year or even within a year, it is more difficult to attract and retain end-use customers as well as others in the value chain.

Demand Response Public Policy

Government rules and regulations play a larger role in most products than is generally recognized. Whether producing consumer goods or services, from apples to zinc, market success can be depend heavily on compliance with government policies such as health, safety, environment, anti-trust, insurance, and energy of course. Since this paper is oriented toward public policy for demand response, part of the education or marketing function needs to include regulatory officials in energy, environmental, and other agencies.

5.2 ISO Economic Demand Response Programs

FERC has actively encouraged ISOs to offer demand response and distributed resource programs.[30] In response, several ISO programs were offered in the summer of 2001. A summary of the California, New England, New York and PJM programs is shown in Table 4.[31]

Each of these ISO programs differed in important respects. The California program offered upfront capacity payments which presented minimum payments that are paid even if the program is never called. This guarantee helped customers make investments in equipment necessary for participation in the demand response programs. Payment channels also varied across programs.

[30] FERC Order of May 18, 2000.

[31] Summarized from Donald Gilligan, "Grading 2001's ISO Demand Response Programs, *Energy User News*, November, 2001. Refinements provided by Glen Perez, CAISO for California. Additions for PJM provided by Steve Fernands, Price Responsive Load Coalition.

TABLE 4
ISO Offered Economic Demand Response Programs in 2001

Subject	CA ISO -DRP	NE ISO Price Resp.	PJM	NY ISO Day Ahead
Period	Jun 1 – Sep 30, 2001; Oct. optional; 11 am – 7 pm wkdys	Jun 1 – May 31, 2002 7 am – 11 pm wkdys	June 1 – May 31, 2001 Any time, any day	2001- Oct 31, 2003 Any time, any day
Eligible participant	Aggregator of end use customer	NEPOOL member for end use customer	CSP or LSE	CSP or LSE
Eligible load	1 MW +	100- 500 kW	100 kW +	1 MW +
Call criteria	Resource shortage	Price $100/MW+	Participant is a price taker	Participant bids
Response period	35 minutes	Variable per notification	Participant sends email	Defined in customer bid for Day Ahead Market
Respondent option	Mandatory; up to 24 hours per month	Optional	Voluntary	Mandatory if accepted DA
Duration	4 hours blocks	Variable	Variable	Variable
Compensation	Reserved demand + energy	Based on hourly energy clearing price	Real Time Location Marginal Price (LMP)	Day Ahead Location Based Marginal Price (LBMP)
Baseline criteria	10 highest out of 11 prior workdays	10 prior wkdys with adjustments	Hour Before	5 highest of 10 prior days
Performance measure	Percent of reserve achieved	Baseline difference	Baseline difference	Baseline difference
Payment channel	Scheduling controller, aggregator, customer	NEPOOL participant, customer	LSE/CSP, end-use customer	LSE/CSP, end-use customer
Metering method	Interval meter	Interval meter, phone line, PC	Interval meter	Interval meter
Notification method	Email or epage to schedule coord., aggregator, end user	Internet based communication system (IBCS)	Customer e-mails PJM before or during curtailment	Day Ahead notification over internet
Software requirement	Up to aggregator.	IBCS	Internet	Internet to ISO
Program fees	None	Negotiated + costs for hardware/software	None	None
Emergency Program	Offered	Offered	Offered	Offered

In addition to these programs, others were offered through the ISOs. CAISO offered a discretionary load control program (DLCP) with day ahead notification versus 35 minutes, acceptable optional metering versus mandatory interval metering, and compensation for energy but not capacity, as well as other differences.[32]

6.0 The Role of Time-Based Measurement of Electric Use

Measurement is a key component in demand response programs. Most applications of demand response require enhanced metering and measurement for success. Proper measurement policies will enable time-sensitive pricing which in turn encourages metering investments.

6.1 Measurement Enables Pricing

A growing number of industry stakeholders believe that a fundamental requirement of an efficient electric power industry is the widespread availability of time sensitive measurement of customer usage. This argues for accelerating the implementation of time sensitive pricing mechanisms at the retail level through policies that promote increased metering of time-based electric use. This would not just be for large commercial and industrial customers but, over time, could include all customers as the costs for this capability continue to decrease.

Another operational motivation for time-based measurement is to move away from dependence on generic load profiles, commonly referred to as load profiling, for end-use customer segments. Generic load profiles mask differences between customers and provide little incentive for LSEs, UDCs or end-use customers to better manage their energy consumption. They also enable gaming to the detriment of a true open market.

6.2 Pricing Enables Investments

Once the enabling infrastructure is in place, the most significant result from time-sensitive measurement and pricing is likely to be the innovation in products and services designed to help customers economically manage their energy. To the extent that regulators imposed fixed-price rates (in part because the metering methods fail to enable a better mechanism), the incentive to develop and offer innovative products and services is reduced.

However, there can still be room for demand response programs in conjunction with fixed-price rates. Not all customers want or should be subject to volatile retail rates. Plus there is a role for the LSE to serve as risk manager, particularly in regulated states. Demand response programs can be offered to customers subject to or choosing fixed-price rates.

McKinsey has estimated that the investment in "…the platform needed for dynamic pricing will create business opportunities worth from $25 billion to $30 billion." [33] Utilities are reluctant to

[32] Communication from Glen Perez, California Independent System Operator, January 2002.
[33] Justin A. Colledge and Jason Hicks, James B. Robb, and Dilip Wagle, "Power by the Minute," *The McKinsey Quarterly*, Number 1, 2002, p. 2. www.mckinseyquarterly.com.

invest in technology in part because of uncertain allowance for cost recover by regulatory commissions. "A utility must therefore receive some assurance from regulators that it will be able to recoup these costs and make a return on the investment."

One approach is to encourage ISOs to factor in the costs of advanced metering undertaken by utility distribution companies, load serving entities and even end-use customers. While the ISO may not have direct jurisdiction over such regulated or unregulated entities, cost sharing arrangements and reviews of demand response activity would help. As has been seen in the program evaluation for the NYISO and for other programs, the savings from demand response programs are substantial. Certainly, they are sufficient to underwrite some if not all the costs of metering.

Such programs can be mandatory or voluntary. Mandatory programs have the advantage of engaging more participants and achieving higher net benefits. Voluntary programs risk having low participation and engaging too many free riders.[34]

7.0 Regulatory Principles for Demand Response

This section presents regulatory principles to stimulate greater use of economic demand response resources. The organizing principles presented below provide a basis for judging demand response programs, including load management and dynamic pricing designs.

P1 — Customer Participation: Demand response markets should be designed to foster participation by customers of all types and sizes.

Market designs should be robust in terms of encouraging customers of different types to participate in and receive the benefits of demand response initiatives. Many electricity customers are not energy professionals and are unfamiliar with the details of how supply side energy markets work. They also vary considerably in their ability to be price responsive. Some are eager and willing to agree to mandatory or involuntary participation while others may only be comfortable with voluntary agreements. Some will have automation and direct load control capability while others will rely on manual procedures. Each of these attributes will be factored into the value of customer demand response the buyer is willing to offer. To accommodate a wide variety of customer groups, the demand response market should be able to address the different value propositions that will be needed by different customer segments.

P2 — Equal Treatment: Demand response markets should be on an equal footing in wholesale markets with generators.

Demand response resources of equivalent size and availability to generation resources should be afforded equal treatment. Demand response resources bring many of the virtues attributed to some generation resources, including dispatchability, reliability, and flexibility.

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[34] Charles River Associates: "TOU Pricing for Mass Markets," 2002.

P3 — Robust Markets: Encourage numerous participant relationships.

Market efficiency is achieved when buyers and sellers can easily interact, which fosters price discovery. Current regulatory practice may result in LSEs setting prices based on expected volumes. As a result, LSEs may resist marketing the demand response concept to customers. It is important that, as the market for demand response develops, all parties be provided with appropriate incentives to participate and create a robust market. Where retail markets are deregulated a customer might see multiple offers for demand response from different CSPs depending on their willingness to accept liquidated damages or have real time metering. In markets with retail choice, open and competitive markets for demand response services should be encouraged.

In creating these markets, equity concerns may arise due to existing investments made by regulated companies that might be stranded if a competing entity offers load curtailment services. Although a robust market is desired, considerations of inappropriate bypass, the potential for costs made under a regulatory regime to become stranded, and equity considerations must also be addressed. Even in markets with retail choice, demand response can create bypass concerns where an LSE has made investments to meet its requirements as the default the provider or as provider of last resort.[35]

P4 — Flexible Metering: Metering arrangements between customers and their counterparties should be allowed under mutually acceptable terms.

Acquiring demand response resources and performance information may require a supplemental investment in either an existing metering upgrade or change, or in the communication to or reading of that meter. The seller or the buyer of that resource should be permitted to reach mutually acceptable terms for compensation.

The metering information necessary to employ demand response effectively into regional energy markets varies with the counterparty perspective and the type of resource. These are private treaty agreements that are integrally tied to the price paid for the resource. No one standard of commerce is necessary. In fact, it may be acceptable to even use aggregate substation, feeder and lateral metering, in lieu of individual customer metering (as in the case of using radio-controlled residential switches).

[35] There may not be many conditions where stranded costs result in a large number of dollars being put at risk; however, investments in metering and demand response infrastructure by regulated entities can be large and some have deferred making these investments due to concerns about future cost recovery, and due to uncertainty about their role if retail markets transition into competition. Reasonable assurances about cost recovery consistent with state regulatory policies are needed.

P5 — Timely Reconciliation and Settlements: Market operators of demand response have an obligation to provide timely feedback of demand response performance and financial compensation.

Effective demand response programs require active end-use customer participation. Most of these customers are not in the electricity business, but are changing their business practices or processes to participate in demand response programs. Timely feedback to customers regarding demand response performance and financial compensation is a key to successful demand response programs, especially for large commercial and industrial facilities. Where possible, the demand response provider should receive feedback on performance and compensation the day after the event with settlements completed no later than 60 days after the event for large accounts. Excessive or inappropriate fees should not be charged for settlement.

P6 — Fair Value: Demand response participants should receive fair value.

Demand response resources should be provided fair value according to their benefits to the market. The final value for demand response will depend upon the regional markets along with any location specific attributes. Some may consider these regional markets on a capacity basis while others may seek energy only resources. It is likely that demand response will reduce losses, transmission congestion, and thereby improve reliability. The value for these improvements may be additive and reflect the value of demand-response as a method of alleviating constraints at load centers, i.e., it is effectively already delivered and net of losses. This value becomes more compelling when demand response reduces the final clearing price in a congested spot market.

P7 — Multiple Program Participation: Customers should be permitted to participate in both economic and reliability markets.

Some facilities may be able to participate in emergency programs with short notice as well as buy-back programs with longer notice. There is a distinct possibility that emergency reliability needs do not coincide with market prices. Experience in the Southeast indicates that high market prices occur less than 30% of the time during which the Southeast has a critical peak load condition. That is, more than two-thirds of the time, there would be no reason for an energy company in the Southeast to offer their customers a price signal based upon local supply conditions. Customers should be able to participate in multiple programs as long as the value contribution in each is clear, and that payments to the customer reflect actual value delivered by participation in each program. [36]

[36] There are instances where customers can effectively participate in more than one demand response program without "double-dipping", i.e., being paid twice for the same resource without adding incremental value to each program in which they participate. It can be argued that it has been too easy for policy makers to simply deny customer participation across programs rather than work-out the market design that compensates participants appropriately and encourages the economic participation of demand-response resources in all programs.

Therefore, emergency payment programs should neither forbid participation in an economic program nor encourage gaming. Similarly, customers with demand response resources should be permitted to participate in both capacity and energy markets, where these exist, just as with generators.

P8 — Agreements for Regulatory Information Only: Customer agreements should be confidential and subject to streamlined regulatory review.

Agreements for demand response between market participants often take into account numerous factors not easily subject to regulatory standardization. Payment terms alone can have multiple variations in levels, structures, and timing of both incentives and penalties. Other factors subject to negotiation include notification, operations, measurement, and reporting. For large accounts, bilateral transactions can be complicated and time consuming to negotiate. Furthermore, once agreements are reached, time may be of the essence to achieve reliable demand response. Regulatory guidance should allow these agreements as much latitude as possible. If anything, regulatory responsibilities should be limited to post hoc review and analysis.

Agreements are often so unique that comparisons become difficult without careful analysis. Exposing one part of the agreement such as pricing terms and conditions to public attention can compromise the relationship between involved parties as well as complicate relationships with other parties. Therefore, regulatory review should carefully protect confidential information. Private party agreements should not be subject at all to regulatory review.

P9 — Coordinate Regulatory Review and Oversight: Regulators who have jurisdiction over demand response programs should work cooperatively to remove barriers to implementation.

The implementation of demand response programs can require the coordination and cooperation of multiple federal and state regulatory bodies. These include FERC, DOE, EPA, state PUCs environmental agencies, as well as RTOs, regulated distribution utility companies and aggregators. It is imperative that these groups work with a sense of urgency and with a common purpose. Such cooperation would go a long way to help eliminate impediments to and encourage the development of demand response programs and resources.

8.0 Recommended Regulatory Actions

The principles of demand response presented above provide a backdrop against which efforts to promote demand response should be judged. This section presents some specific recommendations for regulatory action.

A1 — Stimulate better reporting on demand response resources.

There is too little knowledge about the numbers, types, and participation in demand response programs. Such a process could be managed by the RTOs/ISOs under FERC jurisdiction with state PUC cooperation.

Another approach suggested was to encourage the U.S. Department of Energy and state public utility commissions to report on demand response.

A third approach would involve modifications of reports by utility distribution companies to report to the EIA to accommodate more information on demand response activity.

Taking care to protect confidential information, the report, at a minimum, should document the number of resources recruited for demand response and the amount actually realized. The report would document types of programs, numbers of participants, and other information to help educate parties and encourage the adoption of demand response resources.

A2 — Establish goals for demand response.

Goals for demand response would work to focus the efforts of market participants on attaining tangible, cost-effective demand response resources. To assess whether goals are met, processes are needed to track and measure the contributions of demand response resources. Goals can be set in terms of a percent of ISO peak resources and could vary somewhat from region to region. The ISO would document the level of resources available for demand response, although not necessarily called upon. This would include programs offered by the ISO and by others in the region. Demand response resources would be defined comprehensively to cover the entire range of load reduction programs, dynamic pricing programs and distributed resource capabilities. The goal could be set as a percent of ISO peak load for a target year taking into account regional considerations.

A3 — Allow fair cost recovery for demand response.

Uncertainty about cost recovery for demand response programs has severely inhibited necessary investments. Given the significant benefits available from demand response programs, cost recovery should be assured. Since the technologies involved in demand response are changing rapidly, fair cost recovery helps ensure that state-of-the-art systems continue to be developed and are deployed.

A4 — Design demand response into markets at the outset to provide greater value.

It is important to include demand response resources as early as possible in market design efforts and operations. Supply-side resources have historically been accorded significantly more attention than demand-side resources — simply their larger magnitude relative to identified demand response programs makes it absolutely critical that market rules for generation be well designed. However, there may be a natural tendency to favor supply-side resources over demand-side resources where they might provide comparative value because energy officials are more familiar with generation as a resource.[37] To the extent that policies ignore demand response, the resources may be placed at a competitive and operational disadvantage well into the future.

As an action item, FERC should identify "best practices" as starting points for the entire market, and with clear objectives, in principle, describing how demand response will be able to participate. Such actions will provide market certainty to encourage continued investment. Strong signals that demand response markets will be an important characteristic of any RTO will allow interested potential market entrants to make investment decisions with greater degrees of confidence and with sufficient lead-time to participate on Day one.

A5 — Improve standardization of interconnection rules.

Interconnection rules vary across jurisdictions, types of resources, and nature of market participant. Some rules are unduly burdensome and limiting to demand response resources. There is value to establishing "best practices" and standardizing in a way that promotes open architecture software, common measurements, and other specifications to encourage demand response resources.

FERC should assert its authority, at a minimum, by standardizing interconnection rules for the transmission system. On the other hand, there are differences of opinion about whether standardized federal interconnection rules are necessary or appropriate at the distribution level. One advantage of adopting such "best practices" for interconnection at the transmission level would be to help eliminate seams among ISOs and among demand response programs.

A6 — Encourage examination of environmental rules to foster demand response resources.

Some demand response resources are heavily restricted by environmental rules. For example, emergency or backup generators represent a large potential demand response resource. In some jurisdictions emergency generators may be permitted to operate only after the power goes out at a facility, and not to prevent outages. In others, only natural gas fired generators are permitted to operate for economy based demand response purposes.

Overall, demand response resources, including some distributed generation resources, can be environmentally beneficial. Appropriately managed, the net affect of demand response resources can be positive for the environment. It is likely that by viewing demand response resources as a portfolio or collectively, from an environmental perspective, greater deployment may be realized. Therefore, energy commissions should work with environmental authorities to re-examine policies and encourage a comprehensive view of using energy and the environment wisely.

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[37] Neenan Associates (2002) reported the LSEs in New York thought there was a perceived bias toward supply-side resources.

A7 — Appropriately phase out price caps to encourage demand response.

Demand response resources are particularly effective in reducing price volatility of electric prices. To the extent volatility is restricted by regulatory as opposed to market forces, demand response resources are inhibited. Short-run impacts occur when existing demand response resources are not called upon and they could be deployed to mitigate high market prices. Longer-term impacts may occur by reducing investments in demand response resources. Regulatory restraint through minimizing the use of price caps would help stimulate greater use and investment in demand response resources. There may be a short-run regulatory preference for price caps to address concerns about market power; however in the long run, an examination should be undertaken to determine whether better designed market-based checks and balances and appropriate regulatory oversight might better address market power concerns.

A8 — Establish tariffs based on costs, including risk management costs.

Risk management or insurance costs have historically been embedded in regulated rates. Markets with retail choice have often mandated default service rates at levels that do not fully reflect the risk management costs, that is, they do not permit default service providers to recover the full cost of managing the risk they incur providing service at a fixed regulated rate. That puts the default service provider at serious economic risk. It also puts competitive market participants at a disadvantage, as they must reflect these costs in their prices if they offer a fixed rate service. Furthermore, fixed prices mask price volatility, which some market participants are willing to share with their end-use customers in ways that can reduce energy bills significantly.

The key to resolving this problem is explicit regulatory action to ensure, at a minimum, that the provision of fixed-price electricity includes an insurance policy, as well as the electricity commodity. In markets with retail choice, shopping credits that are set without due recognition of risk management costs should be adjusted.

While regulators should include the "insurance" costs in default service rates, regulators also can reduce these costs by giving default service providers the ability to manage their market risk by allowing them to offer their consumers a range of load reduction options. Complementing policies that make explicit the "insurance cost of service" in default tariffs, a companion policy that sets targets for time-sensitive pricing and load response may be beneficial.[38] Understanding quantity and price risks in standard offer and default service tariffs may require additional metering and measurement for select customer segments.

[38] It was pointed out in discussions that one advantage of adding these options to POLR or Default Service is the potential to stimulate competition and switching to LSEs by customers not inclined toward time-sensitive pricing and advanced metering. However, a possible counterproductive result, in terms of inhibiting competitive switching among providers, could be to retain customers using POLR and standard offer rates based on time-sensitive pricing. If behaviors follow as expected, average bills should be lower. Given these issues, managing this process over time may be the most appropriate policy option.

A9 — Make decisions on metering timely with fair information ownership.

Advanced metering is essential to greater demand response participation. This is the case not only for load management programs, but also for price responsive programs. In the absence of clear cost recovery policies, market participants are unwilling to make necessary investments. Advanced metering can occur with either a regulated monopoly or a competitive market, but it will likely not occur until regulators decide on the framework for such metering and infrastructure issues.

Related to the need for advance metering is the access to the information. In some jurisdictions, it has been determined the customer does not own the metering information. Accordingly, the customer does not necessarily have access to the data, either immediately or later. Regulators should allow customers not only to access metering information, but also to take ownership for their own purposes.

Appendix 1 : Existing Demand Response Landscape[39]

Mass Market Programs

There are numerous demand response programs in place and more are being planned or implemented in both residential mass markets as well as among commercial and industrial customers. This section highlights different types of mass market programs.

Residential programs for demand response have been used for over twenty years, although participation has waxed and waned as utility objectives have shifted. The early tradition has been for mandatory participation among customers, who enrolled. More recently voluntary programs are being deployed.

Direct Load Control

Direct load control (DLC) programs target customers with equipment that can be turned off or cycled for relatively short periods of time.[40] The most common applications are, in order of participation rates:

- residential central air conditioners,
- water heaters,
- swimming pool pumps, and
- electric space heaters with storage features.

Receiver systems must be installed on the customer equipment to enable communications from the utility and institute controls. Communications are often by radio signal from the utility. However, the power line carrier is of growing interest, as is the use of public or private wireless communication systems.

DLC programs are mandatory typically, once a customer elects to participate. Voluntary participation is now an option for some programs with more intelligent control systems and override capabilities at the customer facility. Of course, such voluntary behavior may be reflected in lower payments for participation.

Typically, the utility is authorized to cycle or shut-off a unit for a limited number of hours for a limited number of occasions. Cycling strategies for air conditioners range widely:

- 25% cycling or 7.5 minutes off out of 30 minutes,
- 33% cycling or 10 minutes off out of 30 minutes,

[39] Extracted and revised from "Peak Load Management or Demand Response Programs," Association of Energy Services Professionals International, August 2001.
[40] Utilities with programs include Allegheny Electric Cooperative, Exelon (Commonwealth Edison), GPU, Exelon (PECO), PEPCO, and PSE&G. Utilities with terminated programs include Ameren (Union Electric) and SRP.

- 50% cycling or 15 minutes off out of 30 minutes, and
- 100% cycling or off all 30 minutes in each half hour.

Typically the unit is free to operate when not cycled off. Thus the resident is assured of some air conditioning under most schemes. A related issue is whether the fan continues to circulate air and help maintain comfort by being in the “on” position as opposed to the “automatic” position that is tied to the operation of the compressor. Most programs just prevent the compressor from operating thereby allowing the fan to circulate air in the home when the customer has it set in the “on” position.

Smarter control systems have built-in memories to recognize how much the equipment has been running and are programmed to cycle at different frequencies so all participants provide similar load reductions. Of course some systems provide no load reduction where the unit is turned off during the curtailment period or the cycling equipment has been disabled by the customer, whether deliberately or not. Most programs factor such “free rider” effects into the calculations of benefits and costs.

Incentives to the customer are based on several factors including:

- type of unit under control such as air conditioner or water heater,
- degree of control such as 30% cycling or 100% off,
- the average amount of load reduction net of free rider effects, and
- the value of the load reduction to the utility.

Incentives are typically paid through monthly credits on utility bills. These may be just for the load control season or all year as a reminder of the customer’s value to the utility. Customers typically do not have to pay for the equipment or installation of control systems.

Key issues include disrupting customer comfort and convenience. However, the presence of millions of households in these programs attests to their utility appeal and customer acceptance.

Demand Bidding or Buyback Programs

Demand bidding or buyback programs are available when the residential customer is willing to forego using electricity at a price. Typically these are voluntary programs since the customer has a choice about whether and how much to participate on any particular day.

These are very new programs that in many cases are still in the pilot test stage. One enabling technology is a programmable thermostat which controls the air conditioning and heat systems. The thermostat can be programmed to increase settings in the summer or decrease settings in the winter by various amounts. Furthermore, there is a transceiver in the thermostat to allow communication with the utility control center.

One current configuration is designed for direct load control where receipt of a utility signal causes the thermostat to shift to a higher setting in the summer. This has the effect of turning off the compressor on the air conditioner. Electric water heaters are also good prospects for direct load control.

The demand bidding or buyback configuration allows the utility to send price signals. If an air conditioning system is engaged, the thermostat can be programmed to adopt different settings depending on the price level offered by the utility. At a lower price the thermostat adjustment may be small and the compressor will only be off for a relatively short period. At a higher price the adjustment may be large and the compressor may not come on again for hours. The thermostats also have a notification feature to alert residents of calls for action as well as an override feature in case the customer chooses not to participate for the particular event.

Various internet based programs are also in development. Here the customer obtains information on buyback rates via internet connections and takes appropriate actions to manage peak loads, while selling its unused energy back as real-time prices.

A key issue for buyback programs is how sophisticated or complex to make the price signals. There is also the issue of verification to confirm some benefit was obtained when the thermostat and air conditioning system responded.

Time-of-Use Rates

Time-of-use (TOU) rates are designed to more closely reflect the utility cost structure where rates are higher during peak periods and lower during off-peak periods. Both voluntary and mandatory programs may be found.[41]

Voluntary programs allow customers to opt in and later opt out, although they must stay for an agreed upon period of time, such as one year. These programs favor people with lifestyles and equipment inventories using more energy during off-peak periods. This presents a serious issue for voluntary programs because utilities may experience revenue losses as only participants with favorable load profiles participate.

Mandatory programs are designed for whole segments of customers and all must participate. For example, all customers over a certain usage may be required to take energy under a TOU rate. Or all new customers may be placed under a TOU rate.

If rates are designed properly and customer behavior changes within reasonable expectations, utility revenues may be neutral under mandatory programs. That is, customers saving money under TOU rates would be offset by customers paying more. When behaviors change to reduce peak demand and shift usage to cheaper time periods, load factors are improved and, over time, all rates can be adjusted down as compared to without TOU rates.

Key issues involve metering, billing, and customer education. Advanced meters are required typically at each home to record usage by time-of-day as opposed to measuring usage over the

[41] Utilities include Allegheny Power, Cinergy, GPU, NYSEG, Exelon (PECO), PEPCO, and PSE&G.

normal monthly billing cycle. Advanced meters require more sophisticated reading and calculating systems to translate the usage into bills for payment.

Due to the internet, changes are taking place with TOU rate programs. Advanced meters can be tied into communication systems that allow customers to see energy usage as the month proceeds. Through personal computer connections with servers owned by utilities or their business partners, customers can determine costs and take actions to reduce or shift loads to cheaper times of the day or week.

Other key issues involve the definitions of peak and off-peak periods. Some utilities have two pricing periods per day, others three, and others four. Usually weekends and holidays are considered off-peak. A particularly challenging issue is what rates to charge in each rating period since various theories can be adopted to allocated fixed and variable costs among not only classes of customer but also periods of time.

Commercial/Industrial Program Options

Peak load management programs are also available for the commercial and industrial (C/I) class of customers. In fact, more variety exists for these kinds of programs.

Interruptible Programs

For decades, utilities offered interruptible programs for the primary purpose of system reliability.[42] Characteristics of interruptible programs were:

- large load reductions of at least 1 MW and usually including the entire facility,
- short notification to comply such as just an hour and as short as ten minutes,
- interruption could be required at any time of the day or day of the year,
- mandatory compliance,
- failure to perform resulted in huge penalties,
- maximum number of interruptions allowed during any year, and
- permanent discounts on electric bills.

Most participants tended to be industrial customers who could interrupt operations for a few hours or a shift. Common participants included those with operations in refining, melting, manufacturing, mining, food processing, and water treatment. Also participating were facilities served by backup generators that could carry all or large portions of the load such as hospitals and data centers.

However, many utilities rarely if ever interrupted these customers. So with the rate discount, such programs evolved more for purposes of economic development than for load management.

[42] Utilities with interruptible programs include Allegheny Electric Cooperative, Allegheny Power, Arizona Public Service, Exelon (Commonwealth Edison), NYSEG, Exelon (PECO), and PSE&G.

Related to the issue of mandatory compliance is the issue of severe penalties. For customers who do not interrupt as requested, utilities have provisions allowing significant penalties. It is no wonder customers drop out of interruptible programs when mandates for performance exceed expectations.

Curtailable Load Programs

To provide an option to the extremes of interruptible programs, utilities offer curtailable load programs (CLP).[43] One utility prefers the term "power down" for these programs. Key characteristics include:

- smaller load reductions expected such as 100 to 200 kW minimum, but as high as 500 kW or 1,000 kW to qualify,
- fewer number of curtailment requests such as 15,
- curtailment requests only during certain days and times, such as weekdays and between 11 a.m. and 7 p.m.,
- mandatory participation once an agreement has been reached,
- small penalties for failures to meet load reduction targets, and
- credits based on amount of load reduced and applied against standard tariffs.

Commercial facilities such as offices and retail can more easily participate and do. Those with backup generators can not only reduce lighting and air conditioning loads but also carry all or part of the remaining load themselves.

One program design option for curtailable load programs is whether to treat participants individually or collectively. Most programs approach facilities individually and reward them separately. However, some programs are set up as cooperatives. In this case the utility works with the facilities as a group, such as those which may be found in one geographical area.

There are many operational issues. But one particularly relevant issue for CLP is how to manage the limited number of hours and days for which curtailments may be exercised. If managers do not husband the curtailments sufficiently well, they may reach the last few weeks of the curtailment season with insufficient resources to call upon should they be needed. However, most utilities are more concerned about the issue of revenue losses during curtailment periods. As a result the end of the curtailment season is often reached without using all the allowed events, particularly in mild summer seasons.

Real Time Pricing

More utilities are offering pricing options based on TOU.[44] Some are standard time- of-use rates which are fixed for entire seasons with peak and off-peak prices. For example 8 a.m. to 8 p.m. on

[43] Utilities with curtailable programs include Allegheny Electric Cooperative, Allegheny Power, Ameren, Arizona Public Service, Cinergy, Exelon (Commonwealth Edison), GPU, Exelon (PECO), PEPCO, and PSE&G.
[44] Utilities with TOU programs include Ameren, Cinergy, Exelon (Commonwealth Edison), GPU, NYSEG, Exelon (PECO), PEPCO, and PSE&G.

weekdays may be the peak period and cost twice as much as other times which are all considered off-peak, including weekends. TOU programs have been successful in promoting the use of load shifting technologies such as cool storage with ice or water.

A more refined alternative is real time pricing where prices vary hour by hour.[45] Customers may volunteer to participate but must usually remain in the program for some specified period of time, such as one year. Program designs include:

- day ahead pricing with hourly costs,
- day of pricing with hourly costs, and
- voluntary load changes on part of the customer.

Sophisticated customers can tie the utility pricing scheme into their energy management system. Greater price differentials between high and low costs periods can automatically trigger greater shifts of energy usage.

More commonly, customers make decisions day to day. For example, some customers may choose to pre-cool a facility in the morning when rates are lower and coast through at a higher temperature in the afternoon when rates are higher. This may work for normal occupancy or use of a store, office or factory. However, if the facility is operating at a high occupancy or capacity, customers may choose to "buy-through" during premium cost periods and not change operations.

There can be significant savings when power is inexpensive. The risk is whether the cheap hours are offset by expensive hours. Customers appear satisfied with real time pricing programs as indicated by their long tenure and increasing numbers for the largest and most successful program.

Demand Bidding or Buyback Programs

Under demand bidding or buyback programs, the customer remains on a standard rate but is presented with options to bid or propose load reductions in response to utility requests.[46]

How to determine offering prices is one of the issues on demand bidding programs for utilities. There are four general pricing schemes.

- A fixed percentage of the wholesale spot market price is offered to customers. The percentage has been found to vary from utility to utility in part due to whether they wish to recover administrative costs and earn a margin.
- A variable percentage of the wholesale spot market prices is offered by some utilities. The percentage varies according to system and market conditions.
- A fixed price whereby the customer determines at the beginning of the program what amount of load it will provide at a specified price. Then the utility can call on those customers agreeing to the lowest buyback prices first and call on others as needed.

[45] George Power has one of the most successful programs with involving 1,700 customers and 5,000 MW.
[46] Utilities with demand bidding include Allegheny Power and GPU.

- A variable price which the customer determines. The variable price may be determined for each event by the customer or may be within a range agreed to with the utility. When the customer bids in response to the utility request, the utility can rank the bid loads and prices to decide how much to take and from which customers.

In addition to utilities offering to buy back energy on the basis of time, refinements are also being made on the basis of location. Congestion can occur on the transmission and distribution facilities of utilities. So rather than calling for capacity reductions solely for generation purposes, utilities can call for load reductions in certain neighborhoods and regions. Furthermore, the utility can offer more incentives in some regions than other regions for the same period of time to balance generation capacity needs with transmission and distribution needs.

To accommodate the load and pricing options, utilities are forming alliances with power exchanges. Similar in concept to a stock exchange, the power exchange facilitates transactions by matching offers to buy power with offers to sell power. This raises issues of ensuring the various parties live up to the agreements regarding settlement of energy and financial obligations.

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