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The Role of Demand Resources In Regional Transmission Expansion Planning and Reliable Operations

July 2006

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The Role of Demand Resources In Regional Transmission Expansion Planning and Reliable Operations

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July 2006

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ACRONYMS

BPA	Bonneville Power Administration
CAISO	California Independent System Operator
DADRP	Day-Ahead Demand Response Program
DCLM	direct control load managment
DSM	demand side management
ECAR	East Central Area Coordination Agreement
EDRP	emergency demand response program
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
GMP	Green Mountain Power
ICAP-SCR	Installed Capacity Special Case Resource Program
ISO-NE	Independent System Operator of New England
ISO	Independent System Operator
LIPA	Long Island Power Authority
LMP	locational marginal price
MAAC	Mid-Atlantic Area Council
MAIN	Mid-America Interconnected Network
MISO	Midwest Independent System Operator
MOD	Modeling, Data, and Analysis group of NERC standards
MRO	Midwest Reliability Organization
MTEP	Midwest ISO Transmission Expansion Plan
MW	megawatt
MWh	megawatt-hour of energy
NERC	North American Electric Reliability Council
NPCC	Northeast Power Coordinating Council
NYISO	New York Independent System Operator
NYSERDA	New York State Energy Research and Development Agency
PDCI	Pacific Direct Current Intertie
PEF	Progress Energy Florida
PJM	PJM Interconnection L.L.C.
PSC	Public Service Commission
PUC	Public Utility Commission
RFC	Reliability First Corporation
RRO	regional reliability organization
RTEP	regional transmission expansion plan
RTO	regional transmission organization
SCE	Southern California Edison
SERC	Southeastern Electric Reliability Council
SPP	Southwest Power Pool
TO	transmission owner
TPL	Transmission Planning group of NERC standards
UFLS	under frequency load shedding
UVLS	under voltage load shedding
WECC	Western Electricity Coordinating Council

EXECUTIVE SUMMARY

Investigating the role of demand resources in regional transmission planning has provided mixed results. On one hand there are only a few projects where demand response has been used as an explicit alternative to transmission enhancement. On the other hand there is a fair amount of demand response in the form of energy efficiency, peak reduction, emergency load shedding, and (recently) demand providing ancillary (reliability) services. All of this demand response reduces the need for transmission enhancements. Demand response capability is typically (but not always) factored into transmission planning as a reduction in the load that must be served. Much more demand response is used (involuntarily) as load shedding under extreme conditions to prevent cascading blackouts. The amount of additional transmission and generation that would be required to provide the current level of reliability if load shedding were not available is difficult to imagine and would be impractical to build. In that sense demand response *is* utilized as an alternative to transmission expansion and is included in regional transmission expansion planning and reliable operations.

In a very real sense demand response solutions *are* equitably treated in every region – when proposed, demand response projects are evaluated against existing reliability and economic criteria. The regional councils, RTOs, and ISOs state that their role is limited to identifying needs. Others propose transmission, generation, or responsive load based solutions to address the needs identified by the regional organizations. Regional reliability organizations state that it would be inappropriate for them to favor one technology (demand response) over others (generation and transmission. Few demand response projects get included in transmission enhancement plans because few are proposed. But this is only part of the story. Several factors are responsible for the current very low use of demand response as a transmission enhancement alternative. First, while the generation, transmission, and load business sectors each deal with essentially the same amount of electric power, generation and transmission companies are explicitly in the electric power business but for most loads electricity is not the primary business focus. This changes the institutional focus of each sector. Second, market and reliability rules have, understandably, been written around the capabilities and limitations of generators, the historic resources for reliability. Responsive load limitations and capabilities are often not accommodated in markets or reliability criteria. Third, because of the institutional structure, demand response alternatives are treated as temporary solutions that can delay but not replace transmission enhancement. Financing has to be based on a three to five year project life as opposed to the twenty to fifty year life of transmission facilities.

More can be done to integrate demand response options into transmission expansion planning. Given the societal benefits it may be appropriate for independent transmission planning organizations to take a more proactive role in drawing demand response alternatives into the resource mix. Existing demand response programs provide a technical basis from which to build. Regulatory and market obstacles will have to be overcome if demand response alternatives are to be routinely considered in transmission expansion planning.

1. INTRODUCTION

The transmission planning process in the United States is complex, involving many parties with various responsibilities and capabilities. Transmission owners (TOs), system operators, regional reliability organizations (RROs), the North American Electric Reliability Council (NERC), state and federal regulators are all involved. Transmission adequacy is not judged in isolation; it is transmission's ability to connect generation to load that is valued. Whether a given transmission system is adequate or not depends upon the current and future mix of generation and the sizes, locations, and behavior of loads. Both reliability and economics must be considered. A reliable transmission system may still be considered inadequate if it requires the operation of specific high-cost reliability-must-run generators.

Often, the entities with the broadest view (NERC, the regions, regional transmission organizations [RTOs], independent system operators [ISOs]) and able to identify transmission enhancement needs that impact the largest number of people or able to identify solutions that might be optimized over the greatest area have the least ability to implement those solutions. Regional reliability councils and ISOs, for example, own no transmission and have no financial resources that would enable them to build an identified transmission enhancement project. They also often have little authority to order the building of an identified enhancement.

There are almost always generation and load based alternatives to building specific transmission enhancements. Generation can be built closer to load. Load can respond and reduce transmission congestion. This paper examines the way load response is treated in the transmission planning process throughout the United States to facilitate reliable operations. The report attempts to determine if load response alternatives are treated equitably and/or if there are obstacles to their implementation. The task is complicated by the natures of the corporate entities involved. Regional reliability councils and ISOs are required to be independent and not favor one technology or one solution over another. This is good. But this independence may inadvertently place load response at a fundamental disadvantage in today's electric power industry structure. Generation owners and investors will, naturally, advocate for their proposed projects. Transmission owners and investors will similarly advocate for their projects. Both of these types of entities are exclusively in the electric power business. Conversely, loads are not primarily in the electric power business. They use electric power to facilitate their primary objectives. Companies that specialize in load response facilitate that response but do not own the basic resources (the loads). Further, there are transmission planning organizations within almost every RTO, ISO, and regional council. There are similar generation planning organizations. It would be rare indeed to find a responsive load planning organization. This results in a situation with strong advocates for, and significant infrastructure supporting, generation and transmission solutions but relatively little support for load response solutions.[1] In one sense demand resources are treated perfectly equitably; they

[1] Ancillary service rules provide an example. Rules governing the provision of ancillary services by generators often provide detailed accommodation to the limitations of generators. Minimum start times,

simply can not meet the published system requirements. In another sense demand resources are treated inequitably because the reliability rules are often written around generator capabilities rather than around system reliability requirements.

If there are societal benefits to be gained by using load response to enhance the reliability and economy of the transmission system a simple neutrality that equally evaluates any generation, transmission, or responsive load based proposal offered in the current competitive environment may not be sufficient. Load response alternatives may need to be advocated just as generation and transmission solutions are advocated. Because society benefits from load response it may be appropriate for organizations that husband the societal interests in the power system to insure that load response solutions are fully considered, even absent a strong commercial advocate. This may be different than simply insuring that any proposed alternatives get an equal hearing.

Personnel from the various reliability organizations were interviewed in the process of researching this report and the author is grateful for the time, effort, and knowledge they shared. Planning documents and reliability rules were also reviewed. Few clear examples of load response being proposed, evaluated, and used as an alternative to transmission enhancement were found, however. Many organizations have a policy to be non-biased and evaluate all alternatives on an equal basis. They state that they are prohibited from specifically seeking demand response solutions. When few demand response alternatives are found this could be because loads have little interest in providing response, the organization is biased against demand response, the demand response technology is inadequate, market rules do not favor demand response, or reliability rules do not favor demand response. Distinguishing between these causes requires examining the characteristics of load response that might be useful and how various organizations treat load response.

The report is organized into an executive summary and six chapters. Chapter 1 is this introduction. Chapter 2 provides a brief discussion of the overall transmission planning process and how demand response is typically treated in that process. The various types of demand response are then discussed in order to understand how demand response can impact power system reliability. Particular attention is paid to responsive load providing ancillary services and emergency load shedding. Chapter 3 discusses the various organizations with transmission planning responsibility, starting with NERC and covering the regional councils, various subregions and ISOs. Some international experience is provided as well. It was not possible to cover all organizations, or even all organizations with significant demand response programs, for this report. Hopefully sufficient coverage is provided to give a sense for the state of the industry. Chapter 4 provides descriptions of example projects. Chapter 5 discusses concerns and obstacles and chapter 6 provides recommendations.

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minimum run times, ramp rates, minimum loads, and regulation range limitations are all accommodated. Similar accommodations for demand resources are only beginning to be made.

2. BACKGROUND

Understanding how demand response fits into transmission planning process, or more explicitly why demand response has had such a limited role as a transmission enhancement alternative, requires examining both the transmission planning process and the capabilities of demand response. This chapter first briefly looks at the transmission planning process and then looks at demand response capabilities.

2.1 TRANSMISSION PLANNING PROCESS

Transmission planning is conducted to identify system upgrade and expansion needs for reliability and economic benefit. Details of the planning process vary from entity to entity but the basic process is the same. The power system is modeled under expected future conditions. When inadequacies in the transmission system are identified there are specific processes that are utilized to find solutions. Typically system planning analysts use load flow, transient stability, and voltage collapse analysis to assess system adequacy. This is an elaborate, well orchestrated, inclusive, effective process which typically provides years of warning concerning the need to upgrade the power system in order to meet the expected needs. The process often distinguishes between system upgrades that are needed to maintain reliability and those that are only needed to facilitate commerce or increase efficiency. This segregation is largely artificial but it is widely used.

ISOs, RTOs, regional reliability councils, and regional planning organizations do not typically have the obligation or authority to directly design or implement transmission enhancement solutions. These organizations are typically independent of markets and required to remain so. Once they identify transmission system inadequacies they publicize the needs and expect transmission, generation, and demand side investors to propose projects to solve the problems. The planners evaluate the proposed solutions to see if they meet the technical and economic requirements. The best projects are endorsed and put into the regional transmission expansion plan. The projects must then be approved by state and federal regulators before being incorporated into transmission tariffs and/or the rate base. The technical opinions of the regional transmission planning organizations typically carry great weight with regulators but the actual authority to select projects does not generally lie with the regional organizations.

The ISO/RTO Planning Committee is an organization composed of AESO (Alberta), CAISO, ERCOT, IESO (Ontario), ISO-NE, Midwest ISO, NYISO, PJM, and SPP. The committee provides a concise description of the evolving state of regional transmission planning:

> Regional electric system planning is evolving. In the early days of an ISO/RTO planning effort, transmission expansion plans often represented a compilation of the member utilities' local transmission plans. As the planning organization and stakeholder relationships grow stronger, the plans grow in scope and complexity, starting with work to conduct reliability planning on an intraregional basis and

> then moving to interregional reliability and economic or environmental improvement projects. Often, the next step is to strengthen the plan to address a particular system need or policy issue that exceeds reliability alone. After the RTO's planners and transmission owners become comfortable with regionally integrated reliability planning, the next step is to look at intraregional and interregional economic opportunities, where new transmission investment can significantly increase interregional flows and reduce costs. (ISO/RTO Planning Committee 2006)

The generation and transmission solutions offered to the regional planner are typically developed by well established competitive generation companies and regulated transmission providers. There are also a few developers of merchant transmission. Demand response solutions do not have an as well developed institutional base. Transmission planners explore a host of possible solutions including upgrading existing lines, building new lines, adding FACTs control devices, etc. Entire separate departments exist to perform the electrical analysis, acquire right-of-way, do the civil engineering design, procure equipment, interface with the effected communities, construction, etc. Actually getting new transmission lines built is difficult but there is a large, elaborate, and detailed process established that exhaustively examines all possible transmission solutions and actively seeks the most desirable. Generation planning is similarly well established. No such similar process exists for examining demand response solutions. Instead, demand response is typically treated as a solution that may be examined if it is offered by others and if the offering meets criteria that were often established based upon traditional transmission and generation technical solutions. Demand response solutions are typically not sought with the active, meticulous, accommodating effort that is applied to transmission and generation solutions.

2.1.1 Demand Response in Transmission Planning

Determining exactly how demand response is treated in transmission planning is not clear-cut. Many organizations state that their responsibility is limited to identifying transmission concerns and evaluating the viability of proposed solutions. Specific projects are to be proposed by generation, transmission, and demand response companies. Conversely, some institutions specifically state that they always evaluate demand response alternatives for transmission enhancements but demand response solutions do not show up in their transmission expansion plans. The ISO/RTO Planning Committee 2006 report states that its nine organizations have approved 1121 transmission projects worth $15.6 billion including 5070 miles of new transmission lines and 133062 MW of approved new generation. In contrast, only 4000 MW of new and existing demand response projects are mentioned and only for New York and California. An additional 500 MW of demand response can be found mentioned within an ISO-NE figure.

In one sense demand response *is* included in almost all transmission planning. Known existing or expected demand response is incorporated into the reliability assessment either as a modification to the expected load or as a responsive resource. Load which is responsive to real-time or time-of-use prices, for example, is accounted for by modifying the forecast peak and off-peak load. Load which responds to system operator calls is used as a responsive resource, similar to generation, to mitigate problems found in the transmission analysis. Energy efficiency measures simply reduce energy requirements and get incorporated into future load forecasts, often without explicit consideration by transmission planners.

PJM has significant demand response programs and is leading efforts to fully incorporate responsive load in ancillary service markets. However, PJM's consideration of one type of responsive load provides an interesting counterpoint to the general trend of considering load response as a load forecast modifier. (Load response is not incorporated into load forecasts in Florida either but the process is not as formal so the reasoning can not be examined as closely.) PJM explicitly does *not* consider economically responsive load in transmission planning. They reason that the load has no obligation to respond so it can not be counted on to do so. PJM feels that this is different from generation that is receiving a capacity payment does have an obligation to respond and can be counted on. This is a reasonable distinction. But the load forecast itself is simply a forecast; the forecasted load has no obligation to show up as load. Load growth forecasts, for example, are based partly on forecasted economic and weather conditions. A great deal of transmission planning is necessarily based on uncertain forecasts rather than on established obligations. Hence it seems reasonable to consider responsive load as a load forecast modifier in some fashion regardless of the obligation to respond.

What is not typically done is to include new demand response as a potential solution to transmission adequacy problems. Demand response is not considered equally when a system planner lays out options for dealing with the discovered transmission inadequacies. BPA and MISO have policies calling for demand response consideration but these have not resulted in actual projects.

2.2 LOAD RESPONSE

There are five basic types of load response as shown in Figure 1. All of them impact transmission adequacy, some can be used as direct substitutes for transmission enhancement. Energy efficiency reduces consumption during all hours and typically reduces the need for transmission. It is not focused on hours when transmission is congested and may not provide as cost effective a response to a specific transmission problem as more directed alternatives. Price responsive load and peak shaving both target specific hours when response is desired. The former facilitates voluntary market response to price signals while the latter utilizes direct control commands. Both types can be used to address capacity inadequacy caused by a lack of generation or a lack of transmission.

2.2.1 Ancillary Services

Responsive load can also provide reliability response in the form of contingency reserves (ancillary services).[2] (Kirby 2003) The load is continuously poised to respond but only has to reduce consumption when a reliability event actually occurs. The response duration depends on the nature of the event and the type of reserve being supplied (Figure 2) but is typically minutes rather than the hours required when peak shaving or responding to price signals. Fast communications are often required to notify the load when response is needed. While loads providing contingency reserve do not reduce transmission loading itself under normal conditions they can reduce the amount of transmission capacity that must be held in reserve to respond to contingencies. This both reduces the need for new transmission and increases the utilization of existing transmission to provide energy from low cost generation.

- **Energy Efficiency** programs reduce electricity consumption and usually reduce peak demand
- **Price Response** programs move consumption from day to night (real time pricing or time of use)
- **Peak Shaving** programs require more response during peak hours and focus on reducing peaks every high-load day
- **Reliability Response** (contingency response) requires the fastest, shortest duration response. Response is only required during power system “events” – *this is new and slowly developing*
- **Regulation Response** continuously follows the power system’s minute-to-minute commands to balance the aggregate system – *this is very new and may have the potential to dramatically change production costs, especially for aluminum and chlor-alkali*

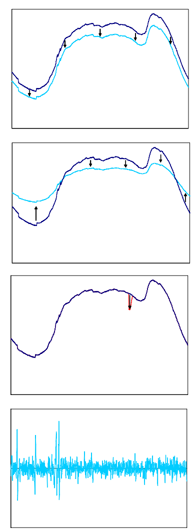

Figure 1 Four of the five basic types of demand response impact transmission adequacy.

Some responsive loads are technically superior to generation when supplying spinning reserve, the ancillary service requiring the fastest response. Many can curtail consumption faster than generation can increase production. The only time delay is for the control signal to get from the system operator to the load. This is typically 90 seconds or less (much less with dedicated radio response), much faster than the 10 minutes allowed for generation to fully respond. When responding to system frequency deviations the curtailment can be essentially instantaneous. Communications delays are not encountered because frequency is monitored at the load itself.

[2] Reliability rules currently prohibit the use of responsive load to provide some ancillary services (spinning reserve for example) in some regions but technically the generation/load balance can always be restored by changing either side of the equation.

An example where responsive load provides superior spinning reserve when compared with generation can be seen in Figure 3. Western Electricity Coordinating Council (WECC) interconnection frequency response is shown for the sudden loss of the Palo Verde unit 1 generator. The lower red curve shows system frequency response with generators providing all of the spinning reserve. The upper blue curve shows that system frequency would not dip as low and would recover more quickly if 300 MW of spinning reserve were provided by a large pumping load instead of from generation. (Kueck and Kirby 2005)

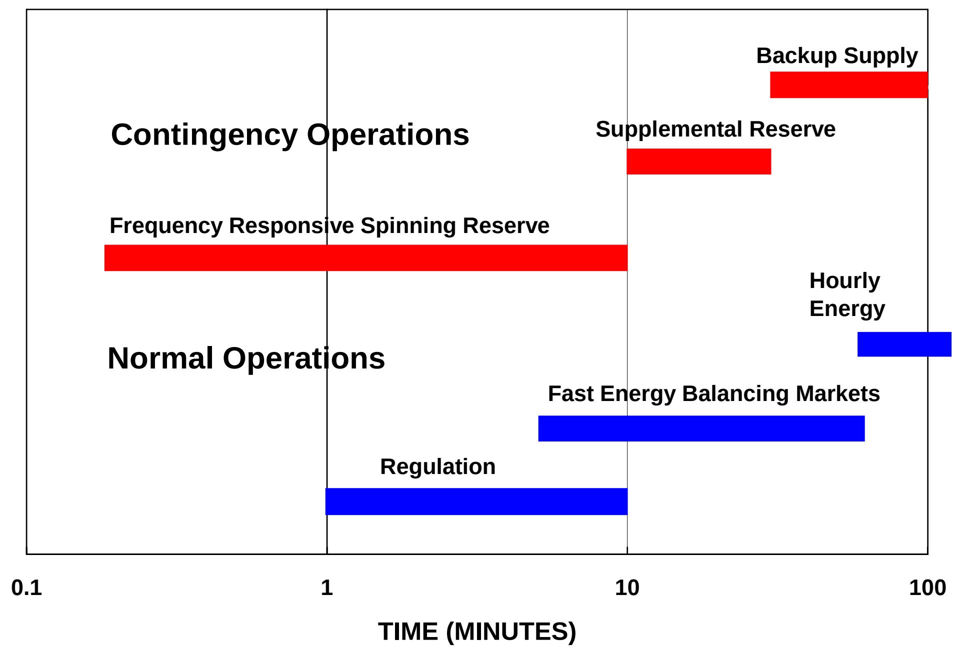

Figure 2 Response time and duration characterize required ancillary service response.

Some responsive loads are beginning to discover that they have the capability to provide regulation, the most expensive ancillary service. Regulation is the minute-to-minute movement of generation (or load) in response to system operator commands to balance aggregate generation with aggregate load. Provision of regulation is not likely to impact transmission adequacy. This type of response is included here only for completeness.

Ancillary Service Markets

Markets for ancillary services typically develop shortly after markets for energy are established. The interdependence between the supply of energy and ancillary services makes this natural. Table 1 shows the current state of ancillary service markets.

Responsive load is typically allowed to provide supplemental (non-spinning) and slower reserves. Restrictions on responsive load providing spinning reserve have eased recently in some areas. The Electric Reliability Council Of Texas (ERCOT) allows responsive load as a supplier of spinning reserve. PJM allows responsive load to supply spinning reserve and regulation. The New York Independent System Operator (NYISO) expects to allow responsive load to supply spinning reserve in the third quarter of 2007. The Midwest Independent System Operator (MISO) is in the midst of ancillary service market design and the supply rules are not yet clear.

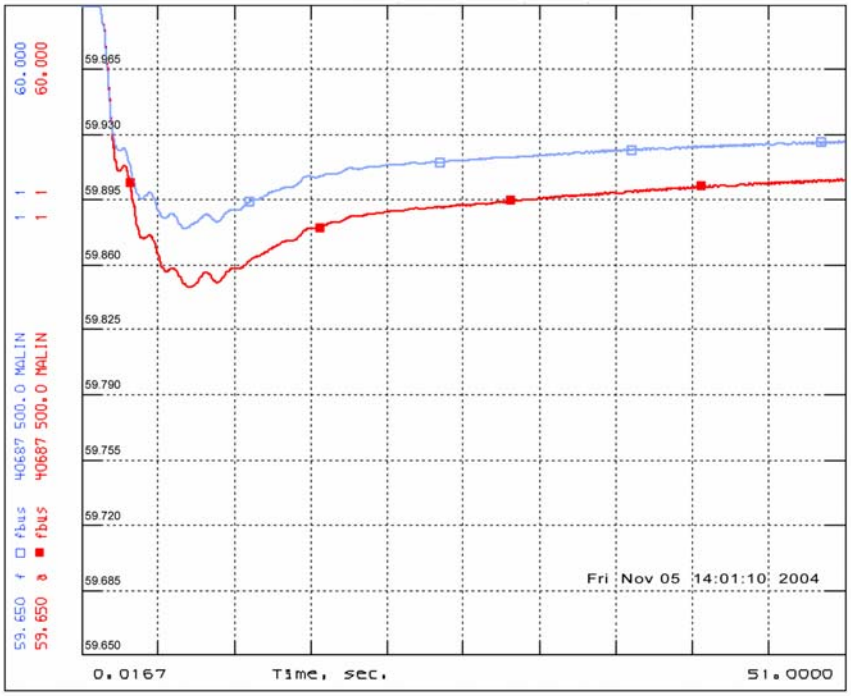

Figure 3 WECC system stability is enhanced when 300 MW of responsive load (upper blue curve) replaces an equal amount of generation (lower red curve). Stability runs performed by Donald Davies of WECC.

Co-optimization of ancillary services and energy markets presents a unique problem for responsive loads. Co-optimization (and in California, the Rational Buyer) is based on the idea that the various services can be ranked in order of "quality". Quality is judged by required speed of response with regulation being the highest quality service followed by spinning, non-spinning, supplemental, long-term supplemental, replacement reserves, and energy supply. The reasoning is that higher quality services can and should always be substituted for lower quality services if the higher quality services are available at a lower price. If not enough replacement reserve is offered into the market but there is an excess of spinning reserve, for example, the system operator is able to purchase spinning reserve and use it as replacement reserve. The reserve supplier is supposed to be indifferent since it is being paid the spinning reserve price and being asked to provide the slower and therefore easier to provide replacement reserve service. This rationale is often extended to allow the system operator to use excess contingency reserves as an energy supply when energy prices are high. This works well for most generators since they are indifferent as to how long they run (they may have minimum run times but generally do not have maximum run times). Unfortunately, this can unintentionally block many responsive loads from participating in reserve markets. An air-conditioning load which can respond rapidly and provide excellent spinning reserve at low price, for example, may be unwilling to provide the multi-hour response required for replacement reserves or energy.[3] The chance that it will be forced to do so by the co-optimizer may block some otherwise excellent contingency reserve resources from making themselves available to enhance system reliability. Very recently this problem has been recognized and addressed in several (but not all) markets. The CAISO, for example, allows responsive load to declare itself as unavailable for providing anything except the reserve market it has bid into. Energy is traded through bilateral contracts in ERCOT so is separate from the ancillary service markets and the problem does not arise. PJM allows resources to submit different capacities in the ancillary service and energy markets so a responsive load can state that it has zero energy capacity. These markets are noted in Table 1 under the "Co-optimization exemption" column.

Table 1 Current and pending ancillary service markets (adapted from MISO 2006)

		Operating Reserves				
	Regulation	Spinning	Non-spinning Supplemental (10 min)	Long Term Supplemental (30 min)	Replacement (60 min)	Co-optimization exemption
ISO-NE	☑	☑	☑ **L**	☑ **L**		No
NYISO	☑	☑ **L**	☑ **L**	☑ **L**		No
PJM	☑ **L**	☑&C **L**	☑&C **L**			Yes
MISO	C	C	C			Not yet set
ERCOT	☑	☑ **L**		☑ **L**	☑ **L**	Yes
CAISO	☑	☑	☑ **L**			Yes

☑ – Market based
C – Cost based
F – Fixed monthly MVAR payment
L – Responsive load is allowed to participate (or will be shortly)
New England has forward reserves for obtaining supplemental and regulation

2.2.2 Load Shedding

Interestingly, the North American interconnected power system has always relied on demand response to maintain system reliability and reduce transmission needs. Theoretically and practically we know that the power system can be balanced effectively by controlling either generation or load. Further, we know that in extreme conditions controlling load is more effective and more reliable. The last line of reliability defense, when things are really serious and the power system is about to collapse, is not increasing

[3] Energy limited hydro generators have a similar constraint an can not afford to risk being called on for extended operations.

generation, it is shedding load. Power system reliability is maintained with automatic autonomous under-frequency and under-voltage load shedding as well as fast "manual" load shedding which responds to system operators' commands. The August 14, 2003 blackout propagated to the extent it did, not because automatic load shedding does not work, but because not enough of it was installed and functioning (U.S. Canada 2004).

Ancillary Services

Ancillary services are those functions performed by the equipment and people that generate, control, and transmit electricity in support of the basic services of generating capacity, energy supply, and power delivery. These services are required to respond to the two unique characteristics of bulk-power systems: the need to maintain a balance between generation and load in near real-time and the need to manage power flows through individual transmission facilities by redispatching generation and load. Table 2 lists the key real-power ancillary services, the ones that ISOs generally buy in competitive markets. (Hirst and Kirby, 2003)

Table 2 Definitions of Real-Power Ancillary Services

Market	Description
Regulation	On line resources (generators and potentially controllable loads) on line, on automatic control, which can respond rapidly and accurately to system-operator requests for up and down movements; used to track the minute-to-minute fluctuations in system load and to correct for unintended fluctuations in generator output to comply with NERC's Control Performance Standards 1 & 2 criteria.
Spinning reserve	On line resources, synchronized to the grid, which can increase output or decrease consumption immediately in response to a major generator or transmission outage and can respond fully within 10 minutes to comply with NERC's Disturbance Control Standard.
Non-spinning reserve	Same as spinning reserve, but need not respond *immediately;* therefore resources can be off line but still must be capable of fully responding within the required 10 minutes.
Replacement reserve	Same as non-spinning reserve, but with a 30-minute response time, used to restore spinning and non-spinning reserves to their pre-contingency status. Also called supplemental reserve.

Note that current rules in some regions do not allow loads to supply regulation or spinning reserves.

NERC and regional standards require Balancing Authorities to have significant load shedding resources; as much as half of the load. As a result of the August 2003 blackout

NERC and Regional rules have been further tightened to assure that adequate responsive load is available to protect system reliability.

Under-frequency load shedding is effective because system frequency is a ubiquitous indicator of interconnection health; loads anywhere within the interconnection can respond automatically and autonomously. If aggregate generation exceeds aggregate load system frequency rises throughout the interconnection. Similarly, if load exceeds generation frequency falls. If either condition persists the power system will collapse. Under frequency load shedding is deployed throughout each interconnection to arrest frequency decay and to restore the generation/load balance. Figure 4 shows that under frequency load shedding is set to respond after (at a lower frequency than) automatic generation control and generator governors respond. (Kirby, Dyer, Martinez, Shoureshi, Guttromson and Dagle, 2002) Under voltage load shedding works similarly to under frequency load shedding to prevent voltage collapse.

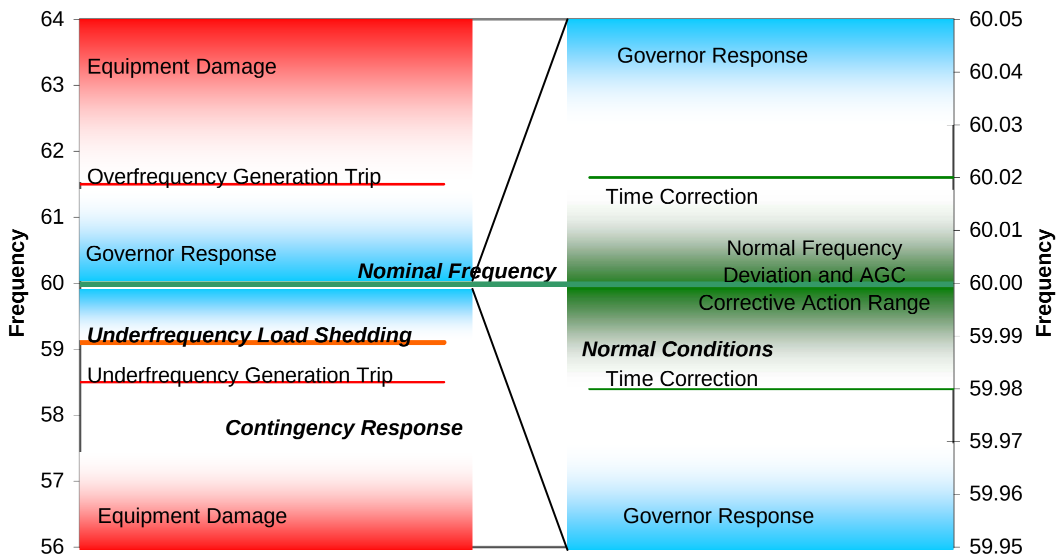

Figure 4 Frequency is a ubiquitous indicator of power system health that is used to coordinate generator and load shedding reliability response.

Load Shedding resources have all of the characteristics of capacity, energy and ancillary service resources but they are not formally categorized as such. There is little point in doing so given the extreme emergency conditions under which they are called upon and their infrequent use. Markets are no longer functioning normally under these conditions and the power system has reverted to reliability-based command-and-control. In load shedding we have responsive (though not voluntary) load not only allowed to provide a large reliability resource but required to do so.

Similarly, rolling blackouts are used under operator control as a last measure when system reliability is known to be inadequate due to insufficient generation or transmission. These instances are, fortunately, infrequent. They are also not voluntary. But they are effective and relied upon. ERCOT used 1000 MW of rolling blackouts, and 1200 MW of loads voluntarily providing responsive reserves on April 17, 2006 to prevent a cascading system collapse. (PUC of Texas 2006) System planners and operators are familiar and comfortable with the effectiveness of this resource. Why then is there so much difficulty in extending this concept of load response as a reliability resource for more frequent use on a voluntary basis as an alternative to transmission expansion?

To be sure, there are important differences between load shedding and other types of demand response. The primary difference is that load shedding is not optional. The implementation reflects this difference. Load shedding is typically accomplished by opening feeder breakers in the utility substation. The process is completely under utility control and is done with utility grade and utility owned equipment. This is different from demand response where the customer is heavily involved, response is voluntary, and customer equipment is used. Still, these are differences in implementation, not fundamental differences in concept. It is likely that technical and institutional solutions could be found that would increase the perceived usefulness of demand response for addressing reliability concerns.

3. PLANNING AND OPERATING ORGANIZATIONS' PROGRAMS

Transmission system planning responsibilities are spread among a number of groups. The North American Electric Reliability Council has responsibility on a continental scale for establishing reliability standards. Regional councils provide added specificity as it relates to the particular needs of their region. ISOs, RTOs, and Balancing Authority (Control Area) operators have very specific concerns with the transmission systems they operate. Concerns with the impact responsive load can have on transmission planning span a broad range. Though it was not possible to conduct an exhaustive survey of the demand response activities of all the organizations with transmission planning responsibility in North America for this report various organizations were selected for inclusion in order to span the geographic scope as well as the range of organizational structures.

The power system in the United States and Canada is split into three interconnections and eight regional reliability councils (Figure 2). WECC and ERCOT are each Interconnections as well as regions. The other six Regions collectively compose the Eastern Interconnection. Asynchronous ties connect the Eastern Interconnection with Western and ERCOT Interconnections. The eight regional reliability councils abide by NERC standards and impose additional requirements of their own on their member Balancing Authorities.

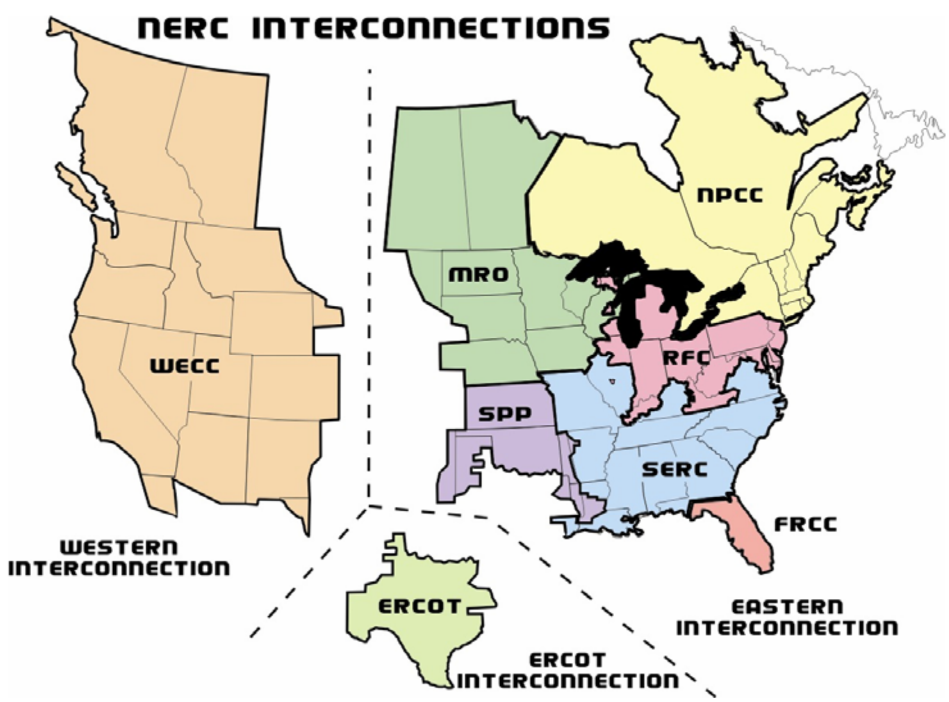

Figure 5 Eight Regions in three Interconnections compose the North American electric power system.

3.1 NERC

The North American Electric Reliability Council is the industry organization which addresses power system reliability. NERC was formed in 1968 as the utility industry organization which develops voluntary reliability rules to govern how the bulk power system is planned and operated. The voluntary structure is being replaced with enforceable reliability rules but the process is only partially completed.

NERC Reliability Standards do not directly address the use of demand response as an alternative to transmission expansion. Instead, forecasted demand and demand response are recognized as impacting the adequacy of the transmission system and reliability rules determine the realizable capacity of the physical transmission system. Consequently, this section examines how responsive load is treated in overall NERC standards. It is hoped that this will shed light on how reliability rules treat demand resources when trying to evaluate the impact of demand resources on transmission planning. This discussion is necessary to examine what is *not* included in the standards as much as it is to see what is there. Even when demand response is addressed the actual content is often quite limited. Since NERC standards are the foundation for reliability in North America and apply to every other entity studied in this paper the examination is felt to be worthwhile.

Of the 23 standards in the Modeling, Data, and Analysis (MOD) group and six in the Transmission Planning (TPL) group only three MOD standards and one TPL standard explicitly address demand side response data requirements (NERC 2006B):

- Standard MOD-016-0 — Actual and Forecast Demands, Net Energy for Load, Controllable DSM (demand side management)
    - Planning Authority and Regional Reliability Organizations must document actual and forecast demand data, net energy for load data, and controllable DSM data.
- Standard MOD 019-0 — Forecasts of Interruptible Demands and DCLM Data
    - Load Serving Entities must provide forecasts of summer and winter peak interruptible demands and Direct Control Load Management (DCLM) response capabilities for the next five to ten years.
- Standard MOD-020-0 — Providing Interruptible Demands and DCLM Data
    - Load Serving Entities must report their interruptible demands and direct load control management capabilities to Balancing Authorities, transmission Operators, and Reliability Coordinators on request.
- Standard MOD-021-0 — Accounting Methodology for Effects of Controllable DSM in Forecasts
    - Load-Serving Entities, Transmission Planners, and Resource Planners must document how conservation, time-of-use rates, interruptible demands, and Direct Control Load Management are addressed in peak demand and net energy forecasts.
- Standard TPL-006-0 — Assessment Data from Regional Reliability Organizations
    - Regional Reliability Organizations are required to provide data concerning actual and projected demands and net energy for load, forecast

methodologies, forecast assumptions and uncertainties, and treatment of Demand-Side Management including program ratings, effects on annual system loads and load shapes, contractual arrangements, and program durations.

Seven additional MOD standards contain guidance concerning collecting and reporting forecast demand and (if interpreted broadly) demand side management program performance data. NERC states that the purpose of these standards includes: "Forecast demand data is needed to perform future system assessments to identify the need for system reinforcement for continued reliability. *In addition to assist in proper real-time operating, load information related to controllable Demand-Side Management programs is needed*" (emphasis added). Forecasted load, with demand response included, drives the need for transmission expansion. The following NERC MOD standards try to assure that accurate demand and demand side response data is collected by requiring the Regional Reliability Organizations "to establish consistent data requirements, reporting procedures, and system models to be used in the analysis of the reliability of the Interconnected Transmission Systems":

- Standard MOD-011-0 — Regional Steady-State Data Requirements and Reporting Procedures
- Standard MOD-012-0 — Dynamics Data for Transmission System Modeling and Simulation.
- Standard MOD-013-0 — RRO Dynamics Data Requirements and Reporting Procedures
- Standard MOD-014-0 — Development of Interconnection-Specific Steady State System Models
- Standard MOD-015-0 — Development of Interconnection-Specific Dynamics System Models
- Standard MOD-017-0 — Aggregated Actual and Forecast Demands and Net Energy for Load
- Standard MOD-018-0 — Reports of Actual and Forecast Demand Data

As can be seen, the NERC standards do not provide guidance on how or how much load response should be used. They only provide guidance on how to report load response capability.

The NERC "Glossary of Terms Used in Reliability Standards" presents an additional concern. (NERC 2006 A) In it "Spinning Reserve" is defined as "unloaded *generation* that is synchronized and ready to serve additional demand" (emphasis added). In the recent past the Glossary has not been considered to be binding and specific requirements have been derived instead from the individual standards themselves. The increasing formality that is part of NERC's transformation into the ERO, coming under the Federal Energy Regulatory Commission (FERC) jurisdiction, and making NERC standards truly mandatory may give added legal weight to the Glossary. In the worst case this could disqualify PJM and ERCOT's use of demand response as spinning reserve. Interestingly, the glossary also defines "Operating Reserves – Spinning" as "The portion of Operating

Reserve consisting of: Generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event; or Load fully removable from the system within the Disturbance Recovery Period following the contingency event." It is not clear which definition applies and if responsive load is allowed to supply spinning reserve.

3.1.1 Load Shedding

Load shedding is draconian demand side management. As mentioned above, it is the system operators' final defense against cascading power system failure and it is extremely effective when designed and operated correctly. In contrast to the sparse treatment of demand side management for normal (and routine contingency) planning and operations in the NERC Reliability Standards, where Demand Side Management and DSM are mentioned 34 times in 8 standards, Load Shedding is mentioned 79 times in 25 of the standards. The acronyms UFLS (under frequency load shedding) and UVLS (under voltage load shedding) are used an additional 167 times. More importantly, while the references to Demand Side Management almost exclusively deal with data reporting requirements *if* demand side programs exist, the standards concerning Load Shedding, especially when coupled with the regional reliability council load shedding standards, address the *necessity* of having Load Shedding.

NERC standards recognize the importance of load shedding for maintaining reliability: NERC states that "a Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection." (Reliability Standard EOP-003) NERC does not currently specify the amount of load shedding that is required, specifying the amount is delegated to the regions Table 3, but NERC does provide extensive guidance on how load shedding systems are to be designed and operated. NERC standards cover the following load shedding areas:

- System operator authority-to-act, requirement-to-act, and training
- Load shedding planning
- Communication among Balancing Authorities and regions
- Coordination between regions and sub-regions
- Data requirements
- Performance reporting
- Under voltage, under frequency, and operator-directed load shedding
- Equipment maintenance

Load shedding is used to address both real power imbalances and lack of voltage support. Failure to have and use effective load shedding was recognized as a cause of the August 14, 2003 blackout. (U.S.-Canada, 2004) Adequate load shedding capability and the willingness to use it was credited with preventing the collapse of the ERCOT system on April 17, 2006. (PUC of Texas, 2006)

Load Shedding: Demand Resources Vital For Reliability

While most forms of demand response are still trying to find their place as accepted power system design options Load Shedding is recognized as a required reliability resource. NPCC, for example, *requires* one quarter of the load to be automatically shed within 0.3 seconds if frequency declines too far. NPCC also requires half of the load to be shed within 10 minutes of a system operators command. (NPCC 2004)

Load shedding is the deliberate blacking out of some customers in order to prevent an uncontrolled cascading failure of the power system. It is required when generation or transmission is inadequate. This typically occurs when a power system is stressed with high load, some generators and/or transmission lines are out for maintenance, and another generator or transmission line suddenly fails. Load shedding can be initiated by system operator command or automatically initiated by under-frequency or under-voltage relays.

Rolling blackouts are a form of load shedding that is used when the generation/load imbalance is expected to last for hours or days. The pain is shared among customers by limiting the duration of each individual's power outage.

Unlike most other forms of demand response, load shedding is not voluntary. Customers do not choose to participate. Entire distribution feeders are shut off rather than individual customers or individual pieces of customer equipment. This is accepted because it is rarely used and because the loads involved were going to be blacked out anyway if the system operator was not successful in preventing a major blackout. The curtailed customers service is also restored more quickly than it would be if the power system failed.

It is difficult to conceive of the amount of additional generation and transmission that would be required to maintain the current level of bulk power system reliability if load shedding were not available. This understanding is compounded by the realization that the August 2003 blackout could have been avoided had load shedding resources been available to and used by the First Energy system operators.

It is interesting that the concept of controlling load to assure power system reliability is embraced so strongly in one case (load shedding) but is often treated skeptically in another (demand response).

Table 3 Significant demand response and load shedding resources exist throughout North America

Region	Interruptible Demand and DSM		Peak Load MW	Load Shedding[#]	
	MW	%		MW	%
Total	21,668	2.6%	821,459	269,634	33%
ECAR*	2,508	2.4%	103,679	20,736	20%
ERCOT	1,150	1.9%	59,702	14,926	25%
FRCC	2,990	6.9%	43,495	17,833	41%
MAAC*	813	1.4%	57,631	17,289	30%
MAIN*	3,350	5.6%	59,314	17,794	30%
MRO	548	1.5%	37,701	11,310	30%
NPCC	1,882	1.7%	107,640	53,820	50%
SERC	5,047	3.1%	165,145	49,544	30%
SPP	920	2.2%	40,906	12,272	30%
WECC	2,460	1.7%	146,246	54,111	37%

*Data in this table on peak interruptible load is from the NERC 2005 Summer Assessment (NERC 2005), prior to the formation of Reliability First and the demise of ECAR, MAAC, and MAIN. Totals, with MRO, remain the same.

#Load shedding includes Under Frequency, Under Voltage, and Operator Directed where available.

3.2 TEXAS INTERCONNECTION AND ERCOT

The Electric Reliability Council of Texas is both a NERC Region and an interconnection which lies completely within the borders of the state of Texas. In 2001 ERCOT consolidated the operation of ten control areas into a single control area with bilateral energy transactions and ancillary service markets serving 20 million people with a peak load of 60,000 MW, 24,000 miles of transmission, and a $20 billion electricity market. Energy is arranged through bilateral agreements. ERCOT obtains ancillary services and balancing energy (15 minutes) through markets. While ERCOT does simultaneous selection of ancillary service resources it does not force ancillary service providers into the energy market.

ERCOT coordinates transmission planning with the various transmission and distribution service providers in Texas. Modeling expected future conditions identifies transmission limitations and helps in the comparison of alternative solutions. ERCOT also determines the transmission enhancements necessary to accommodate generation interconnection. ERCOT distinguishes between transmission enhancements that are required to maintain reliability regardless of the generation dispatch and those for which generation redispatch can be substituted. Demand response alternatives are considered where possible. The ERCOT board approves all major transmission projects. ERCOT determines which transmission provider will build the transmission enhancement and notifies the Public Utility Commission (PUC). The transmission provider applies for and obtains PUC approval to build the transmission enhancement; ERCOT supports the PUC approval process.

ERCOT makes extensive use of load response. Load is allowed to provide responsive reserve (spinning reserve), non-spinning reserve (30 minute response), replacement reserve, and balancing energy. Over 1100 MW of loads qualified to provide spinning reserve and over 1200 MW of loads qualified to provide non-spinning reserve. Over 500 MW of response was observed during recent frequency excursions. Responsive load is currently limited to providing half of the contingency reserves until system operator experience is gained. (Mickey, 2006) Interestingly, not a single load has offered to provide balancing energy while responsive load is providing as much contingency reserve as allowed. This may indicate that load response duration is more limited than response speed.

On April 17, 2006 ERCOT was forced to use 1000 MW of involuntary load response and 1200 MW of voluntary load response to successfully prevent a system-wide blackout. Unusually high and unexpected load due to unanticipated hot weather coupled with 14,500 MW of generation being unavailable due to planned spring maintenance resulted in insufficient capacity to meet load. System frequency dropped to 59.73 at one point. Rolling blackouts were required for about two hours with individual customers being curtailed for between 10 and 45 minutes at a time. All of the load called upon to respond did so successfully (voluntary and involuntary) though there was a 15 minute delay with one block of involuntary load curtailment.

3.3 WESTERN INTERCONNECTION AND WECC

The Western Electricity Coordinating Council is the NERC Regional Reliability Council responsible for the Western Interconnection which encompasses all or parts of fourteen states, two Canadian provinces, and a portion of Mexico. Peak load is about 146,000 MW. WECC does not encourage or discourage demand response; WECC is neutral concerning technology choices for reliability solutions. WECC does not do transmission system planning; instead each of the WECC members plans their portion of the transmission system. WECC does compile the system-wide base cases used by others to plan the transmission system and evaluate the need for new transmission. These base cases incorporate the input from each of the members both for existing conditions and for conditions expected in the future. WECC is not specifically aware of what demand response is included in the information supplied by the members. Expected peak loads may be reduced by the amount of expected demand response. WECC is not aware of any obstacles to greater use of demand response.

The purpose of the WECC Planning Coordination Committee is to (in part):

- Recommend criteria for adequacy of power supply and reliable system design.
- Accumulate necessary data and perform regional reliability studies.
- Evaluate proposed additions or alterations in facilities for reliability.
- Identify the types and investigate the impact of delay on the timing and availability of power generation and transmission facilities.

"The above responsibilities shall not conflict with the responsibilities of the individual Members, pools, and associations to carry out their own coordination of planning and operation within their respective areas." (WECC 2006)

Though it does not perform transmission planning WECC does report on the amount of interruptible demand and demand side management capacity that is available. The breakdown by subregion is shown in Table 4. (WECC 2005)

Table 4 Interruptible Demand and Demand Side Management resources within WECC

	Interruptible Demand MW*	Demand Side Management MW
WECC Total	1950	514
California-Mexico	1352	458
Arizona-New Mexico S. Nevada	285	1
Rocky Mountain	161	0
Northwest Power Pool	160	55

* Note – Total is not the sum of the parts because they are not simultaneous

The WECC 2005 Summer Assessment discusses transmission congestion concerns in each of the subregions. It explicitly discusses recent transmission upgrades that are helping alleviate congestion. It does not discuss demand response as helping to reduce transmission congestion. The closest it gets to connecting demand response with congestion relief is:

> The CAISO control area has 1,610 MW of reliability-related interruptible load programs that may be activated should adverse operating conditions occur. However, only about 1,290 MW of the total is in the more constrained southern portion of the control area. In addition to these reliability-related interruptible load programs, up to 915 MW of additional total-area demand relief may be available, but some of that demand relief is limited by restrictions such as day-ahead notification.

The capacity of the Pacific Direct Current Intertie is impacted by the amount of available demand response:

> The Pacific Direct Current Intertie (PDCI) will have a 3,100 MW north to south (export) limit. The PDCI south to north (import) limit will be 2,200 MW due to lack of direct service industry load tripping remedial action.
>
> …
>
> The Northwest Direct Service Industry, which is composed mostly of aluminum smelters, experienced an electricity consumption decrease from just above 2,500 average megawatts in 2000 to less than 500 average megawatts in 2002.

Though the transfer capacity on the intertie has been reduced because of a reduction in available demand response there is no further discussion of either the value of or methods to increase demand response.

There are a number of transmission planning groups within WECC that are responsible for portions of the interconnection: Southwest Transmission Expansion Plan group (STEP), Northwest Transmission Assessment Committee (NTAC), Southwest Area Transmission (SWAT), Rocky Mountain Area Transmission Study (RMATS), Colorado Coordinated Planning Group (CCPG), and Seams Steering Group – Western Interconnection Planning Work Group (SSG-WI PWG).

WECC has adopted a uniform underfrequency load shedding plan and requires members to have 37% of the load shed in various steps for under frequency conditions. (WECC 2004)

While it was not possible to exhaustively research all of the responsive load programs within the WECC territory for this report it was possible to obtain details on a few.

3.3.1 BPA

The Bonneville Power Administration (BPA) owns and operates 15,000 miles of transmission, about 75% of the high voltage grid in the Pacific Northwest. It owns no generation but it markets wholesale electrical power from federal and non federal generators; about 40 percent of the electric power used in the Northwest comes from BPA. (BPA 2006) At peak use the system transports about 30,000 MW of electricity to customers. (BPA, 2004B)

The Bonneville Power Administration (BPA) has a highly visible effort aimed at identifying non-wires alternatives to transmission enhancement. Load in the Pacific Northwest continues to grow but BPA did not build any substantial transmission enhancements between 1987 and 2003. BPA is concerned that congestion is increasing and reliability may suffer. BPA believes non-wires solutions may be a more cost effective solution while deferring the need to build new transmission facilities. (BPA, 2004A) Non-wires solutions are attractive because transmission constraints are often 40 hours or less per year. New transmission would sit idle most of the time where load could respond without much disruption to its normal operations. BPA cites two past successful demand response projects that justify their current efforts at finding additional non-wires solutions. Traditional conservation measures lowered peak loads on Orcas Island for several years while an underwater cable was replaced. The Puget Reinforcement Project used conservation programs to helped avoid voltage collapse in the Puget Sound area and delayed construction of additional transmission lines crossing the Cascade mountains for ten years. Technological advances in load control and distributed generation lead BPA to think that additional opportunities now exist. BPA has committed to study non-wires solutions before deciding to build any transmission enhancement. (BPA, 2004B)

BPA is now targeting the Olympic Peninsula with a pilot project that started in 2004. The transmission system on the Olympic Peninsula (and in other areas) does not meet NERC reliability criteria. BPA's focus is on deferring transmission enhancement temporarily rather than looking at demand response as a permanent resource. BPA evaluates each project based upon the savings associated with transmission project deferral. A load response project might be viewed as a three year deferral of a $60 million transmission project, for example. In that case the value of the demand response project would be $11 million based on a 7% interest rate. Unlike the ultimate transmission project which load response is delaying, the economic viability of load response would not be examined over the 30 year life of a typical transmission line.

BPA is concerned about the dependability of demand response solutions and is testing this with pilot projects.

BPA identified 20 transmission problem areas in 2001. Nine were designated as high priority. A consultant study was commissioned to examine both the overall BPA transmission planning process and the specific transmission needs. The resulting report recommended process changes in BPA's transmission planning to consider non-wires alternatives early enough that they can make a difference. The report also identified specific projects that might be amenable to non-wires solutions.

BPA formed a Non-Wires Solutions Round Table to obtain opinions from a diverse set of stakeholders within the region. Members included environmental groups, regulators, large energy consumers, Indian tribes, renewables advocates, and independent power producers. They addressed four issues: screening criteria, detailed studies for particular problem areas, non-wires technology, and institutional barriers. (BPA, 2004B)

Specific projects that were identified as candidates for non-wires solutions were:

- Puget Sound Area – the required non-wires load reduction was too large and the wires solution also reduced losses so the Kagley-Echo Lake transmission line solution was selected
- Olympic Peninsula – this was selected as a pilot project to test non-wires technologies including aggregated distributed generation and demand reduction
- Lower Valley Wyoming

Institutional barriers identified by the Round Table include:

- Lost utility revenue – utilities are reluctant to pursue demand response when this may reduce sales and revenue
- Lack of incentive for accurate forecasting – high load forecasts can lead to justifying additional transmission making it more difficult for demand response solutions to be adopted
- Lack of transparency in transmission planning
- Load shielded from actual wholesale electricity price volatility – additional demand response would make economic sense if loads could see the true value of that response

- Reliability of non-wires solutions – this can be both an actual and a perceptual problem
- Funding and implementation – multiple parties can benefit from demand side solutions (generation, transmission, and distribution) but it can be difficult to determine who should pay and who should implement the programs. Partnerships are often necessary but difficult to arrange.

Currently BPA demand response efforts are still at the pilot program state. The first full initiative to actually defer a transmission project may happen late in 2006.

3.3.2 CAISO

The state of California has a very active demand response program supported by the California Energy Commission, the California Public Utility Commission, and the California Consumer Power and Conservation Financing Authority. Responsive loads range in size from residential air conditioners to California Department of Water Resources 80,000hp pumps. California expects to have demand response equal to 5% of the system peak available by 2007. California has established a "preferred loading order" to guide energy decisions. The loading order consists of decreasing electricity demand by increasing energy efficiency and demand response, and meeting new generation needs first with renewable and distributed generation resources, and second with clean fossil-fueled generation. (S. Fromm, K. Kennedy, V. Hall, B.B. Blevins, 2005) California recognizes that, while demand response and distributed generation can defer the need for new transmission renewable resources often increase the need. Quantitative goals are not included for the use of distributed generation or demand response specifically as an alternative to transmission enhancement and coordination with transmission planning is a recognized problem.

The California Independent System Operator (CAISO) was created by the state to operate the power system for most of California including 25,000 miles of transmission lines and a peak load of over 47,000 MW.

The CAISO transmission planning process reviews the transmission expansion plans submitted by the Participating Transmission Owners to assure that they solve identified problems, are the best alternatives, and are the most economical from a system point of view. CAISO performs a comprehensive review to assure that nothing is missing. Management approves projects costing less than $20 million and refers larger projects to the CAISO board for approval. Studies are performed to establish Reliability Must Run generation requirements. CAISO has approved 337 transmission enhancement projects costing over $3 billion. Both the CAISO and the California Public Utility Commission have authority to require transmission enhancements to meet regulatory obligations.

CAISO is proposing a new planning process that is more centralized and proactive. A five year project-specific plan and a ten year conceptual plan will be produced to address reliability and economic needs. Identified projects will be submitted to the transmission owners. Participating Transmission Owners are then expected to submit transmission plans that incorporate the CAISO plan. The transmission plan is designed to eliminate congestion and reliability must run requirements as well as to provide economic signals for generation siting. (Perez 2005) The 2005 CAISO transmission initiatives included seven projects. These included substation and line work but no responsive load projects.

CAISO has a great deal of experience obtaining ancillary services from competitive markets. They operated the first ancillary service markets and are currently redesigning those markets. The redesign should be implemented by November 2007. Responsive loads are currently not allowed to supply regulation or spinning reserves. While CAISO has used a "Rational Buyer" and will now use co-optimization to substitute "higher quality" ancillary services for "lower quality" services and energy supply, responsive loads and energy-limited hydro generators can flag their capability as being available for contingency response only. (Isemonger 2006)

3.4 EASTERN INTERCONNECTION

The Eastern Interconnection is the largest of the three interconnections in North America but it has no organization with overall reliability responsibility. Instead it is composed of six regional reliability councils that coordinate activities to assure that the interconnection remains reliable.

Seams issues with PJM, TVA, and SPP are being addressed through Joint Operating Agreements. The Inter RTO/ISO Council is also developing an inter-RTO/ISO expansion plan process. Vehicles are being put in place to facilitate coordinated joint planning over a vast region but this process does not appear to include much demand response effort.

3.4.1 MISO

The Midwest Independent System Operator manages the transmission system and operates electricity markets for a region that covers all or part of fifteen states and one Canadian province. Peak load is ~132,000 MW; 16% of the total US/Canadian load and 21% of the Eastern Interconnection load. The Midwest ISO Transmission Expansion Plan 2005 (MTEP 05) describes the currently recommended transmission needs for the MISO system. (MISO 2005) The plan identifies 615 facility additions requiring $2.9 billion in investment by 2010. MISO develops the regional plan based upon a roll-up and integration of the individual Transmission Owners' plans. The results are discussed with the Organization of Midwestern States and approved by the MISO board. Interestingly, while the MISO discusses the plan with the states organization the MISO "does not seek nor expect endorsement of any aspect of the plan".

Demand response gets essentially no attention in the MTEP 05. No demand response projects have been identified within the $2.9 billion in reliability investment. Generation redispatch and transmission system expansion are recognized as methods to address inadequate reliability but load response is not mentioned. Line conversion is specifically addressed as an alternative to new construction but not demand response. The description of the process for determining system adequacy, needed additions, and generation redispatch does not have any place for considering load response. This is interesting because the plan does recognize that controlled involuntary load shedding is an effective tool that the system operator can rely upon to contain rare events and prevent uncontrolled outage cascading. “Demand-side options” are mentioned only once in the MTEP 05, when it states that their evaluation is required: “The MTEP process is to consider all market perspectives, including demand-side options, generation location, and transmission expansion alternatives.” There is no indication that demand-side options actually are considered.[4]

There is a brief section on “Load Technologies” which discusses the possible future use of controlled floor heating to help shape wind output to more closely follow other loads. Alternatively, “the load could be used as a dynamic brake for generator stability considerations following a fault on the transmission system.” There is no mention of the adequacy or inadequacy of current load control technologies to address current system needs.

MISO is currently engaged in an active ancillary service market design process that, while not explicitly using load response to address transmission adequacy, is addressing how responsive load can participate in supporting system reliability. (MISO 2006) The MISO stakeholder process is examining how ancillary service markets operate in other regions, including how they accommodate responsive load. That process should result in a FERC filing by the fall of 2006.

3.4.2 PJM

PJM continues to grown rapidly making any description out of date almost as soon as it is written. At this time, PJM serves 51 million people in all or parts of 13 states and the District of Columbia. It has a peak demand of ~135,000 MW; roughly 16% of the total US/Canadian load and 22% of the Eastern Interconnection load. PJM has a long history, starting in 1927 and developed as a tight power pool. In 1997 it became fully independent and started its first bid-based energy market. It became an RTO in 2001. (PJM 2006A)

Transmission planning in the PJM region is accomplished through the Regional Transmission Expansion Planning Protocol which annually generates a Regional Transmission Expansion Plan (RTEP) covering the next ten years. RTEP determines the best way to integrate transmission with generation and load response projects to meet load-serving obligations. (PJM 2006B&C) Over $1.8 billion in transmission enhancement projects have been identified through the RTEP process. Though supply or demand side solutions may be better than transmission enhancement PJM is not authorized to implement them directly. (Glazer 2005) Instead, PJM identifies transmission solutions to problems and, subject to cost/benefit analysis, recommends their implementation through the RTEP if no solution has been proposed by a market participant within a one-year window. PJM’s approach is to give market forces an

[4] There is one further sentence in this otherwise excellent 170 page report that states “In rare situations the ‘redispatch’ can manifest itself as dropping load and backing down generation rather than simply shifting generation among sources.”

opportunity to determine whether transmission investment beyond that needed to ensure reliability is warranted. While PJM planners work with transmission owners to assess the impact of a proposed project on the PJM system the upgrades are the sole right of each transmission owner to construct.

Each RTEP includes: 1) a set of recommended "direct connection" transmission enhancements 2) a set of "network" transmission enhancements 3) a set of market-proposed generation or merchant transmission projects, 4) a set of baseline upgrades and 5) the cost responsibility of each party involved.

Demand response is implicitly included in PJM regional transmission planning as a modifier to forecast load. PJM typically assumes that the current level of demand response will continue into the future when evaluating any specific transmission area.

Though the PJM RTEP process does not explicitly design or select demand response projects PJM is quite active in facilitating demand response in its energy and ancillary service markets. PJM makes extensive use of its market structure to obtain reliability response from commercial actions of generators and loads. Loads participate in long and short term energy markets as well as ancillary service markets. As of May 1, 2006 responsive loads may provide spinning reserves and regulation. PJM is the first RTO to allow responsive load to participate in each of the ancillary services markets.[5] (Bladen 2006, Keech, 2006) Load response in the regulation and synchronized reserve markets is initially limited to 25% of total requirements until system operator experience is gained. Loads are compensated for their capacity contributions as well. PJM has stated that "Demand response should be encouraged so long as it is the right economic answer. However, it is not an end in itself." Current electricity markets insulate retail customers from volatile wholesale power prices and consequently limit short-run demand elasticity. (Glazer 2005)

PJM currently provides two methods for responsive loads to interact with the power markets: the PJM Emergency Load Response Program and the PJM Economic Load Response Program. The Economic Load Response Program pays customers to curtail when the Locational Marginal Price (LMP) exceeds $75/MWh. Both real time and day ahead options are offered. The Emergency Load Response Program pays loads $500/MWh (or the current energy price if higher) to reduce consumption (or to operate on site generation) during system emergencies. Most recently PJM has been expanding these programs to allow loads to supply ancillary services. The Economic Load Response Program had 2209 MW in 122 sites enrolled as of December 2005. PJM paid $11,365,098 for this response in 2005. The Emergency Load Response Program currently has 1619 MW in 3885 sites. PJM's active load management program reduced the 2005 summer peak by 2042 MW and wholesale prices by $1/MWh throughout 2003 and 2004. PJM believes responsive load could potentially reduce the summer peak by 7.5% or 10,000 MW.

[5] Load can not supply black start or reactive power but these are not procured through markets.

PJM addresses the concern that load may not respond by imposing stiff penalties if it fails to follow instructions during emergencies. Load that simply responds to price signals does not face penalties. Only load with a firm commitment to respond, backed by penalties, is credited with reducing system capacity requirements. This presents additional difficulties when forecasting future needs. PJM is seeking four year load response commitments to strengthen their planning.

There are a number of obstacles to increasing the amount of demand response that is available to the power system. Loads should be exposed to wholesale price volatility in order to be provided the correct economic incentives to respond helpfully. Hourly and sub-hourly metering is required to measure demand response. Long term demand response forecasting is the greatest challenge PJM sees. (Bladen 2006)

3.4.3 SPP

The Southwest Power Pool (SPP) is a NERC regional reliability council and a FERC approved RTO for all or parts of Arkansas, Kansas, Louisiana, Mississippi, Oklahoma, New Mexico, and Texas. SPP serves 4 million customers ~39,000 MW peak load with 33,000 miles of transmission lines.

SPP identifies the region's transmission expansion needs through an open stakeholder process. Coordinating with the region's 45 electric utilities, SPP identifies the best overall regional transmission expansion plan. SPP then directs or arranges for the necessary transmission expansions, additions, and upgrades including coordination with state and federal regulators.

SPP does not itself explicitly include demand response in transmission planning studies though it does consider generation as an alternative to transmission enhancement. Individual load serving entities incorporate any current or expected demand response that is within their boundaries in their load forecasts. Individual transmission owners could investigate demand response solutions as alternatives to transmission expansion projects but they are not required to do so by the region. SPP does require 30% of the load to be interruptible on under frequency load shedding relays in three blocks of 10% each.

3.4.4 FRCC

The Florida Reliability Coordinating Council (FRCC) is the regional reliability council for the state of Florida. Transmission system planning for the ~43,000 MW peak load region is dominated by its peninsular geography with all connections to the eastern interconnection made at the northern border. FRCC reports the highest percentage of demand response and interruptible demand of any region; 6.9% or 2990 MW. FRCC has the second highest percentage of shedable load; 41% or 17,833 MW. FRCC coordinates the transmission planning efforts of the members for the region and assesses resource adequacy for the ten year future period.

The PUC has been reevaluating the cost effectiveness of demand side management and has been reducing the rebates offered to consumers. Consequently, the amount of available demand side management capability has been decreasing. Transmission planners do not consider demand response, the demand forecast is not reduced by the amount of expected demand response. They feel that there is not sufficient demand response in any one location to eliminate the need for transmission enhancement. Demand response could delay the need for a project by a year at most.

Still, there is a lot of responsive load in Florida. Progress Energy Florida (PEF – formerly Florida Power Corporation), for example, has a very successful historic 1980's responsive load program that includes 800,000 out of 4.4 million customers. 1000 MW of peak load reduction and 2000 MW of emergency response is available within 2 seconds to 1 minute. Oddly FRCC does not qualify this resource as spinning reserve. (Malemezian, 2005)

Customers can elect which loads to include:

- Air conditioning (4 hrs 50% duty cycle or 3 hrs continuous)
- Electric heat (4 hrs 50% duty cycle)
- Pool pumps (4 hrs continuous)
- Water heaters (4 hrs continuous)
- Central electric heating (4 hrs 50% duty cycle)

Industrial and commercial customers can participate with central cooling systems, their entire load (feeder breaker), or on-site generation.

Two way communications provide a fast deployment signal to all units or selected groups and slower response signals from individuals. The system counts requests, operations, and effective operations which are used to verify system performance. This system is being coordinated with automatic meter reading. PEF is currently only accepting new participants for the winter load reduction program.

3.4.5 NYISO

The New York Independent System Operator (NYISO) was formed in 1998 as part of the restructuring of New York State's electric power industry. Its mission is to ensure the reliable, safe and efficient operation of the State's 10,775 miles of major transmission system and to administer an open, competitive and nondiscriminatory wholesale market for electricity in New York State. Peak summer load is ~32,000 MW. The NYISO's market exceeded $10 billion in 2005. (NYISO 2006)

The NYISO is an outgrowth of the New York Power Pool which was formed following the Northeast Blackout of 1965. The Power Pool coordinated the statewide interconnected transmission system and economically dispatched the generation fleet.

NYISO recently initiated a Comprehensive Reliability Planning Process which identifies reliability concerns and transmission needs. This process involves extensive modeling, considering expected loads, generation resources, transmission limitations, and demand response resources including the Emergency Demand Response Program and Special Case Resource programs discussed later. The process identifies reliability based needs rather than solutions. Generation, transmission, and load response based projects can be proposed. NYISO selects acceptable solutions based on their technical capability to address the identified problem and the economic viability. Only in rare cases when no acceptable solutions are proposed does the ISO discuss compelling a transmission owner to construct a transmission based solution (backstop solution). Much as with PJM, the NYISO intends this process to promote market based solutions to reliability problems. NYISO selection is intended to speed other regulatory approval. There are currently no forward capacity markets but prices are transparent and investors can forecast income. Forecasting energy market income is more difficult due to fuel price volatility.

Transfer limits into southeastern New York are limited by voltage rather than thermal constraints with a significant need arising by 2008. 1750 MW of generation or load response will be needed by 2010 in order to free up voltage support capability. As a partial response to this problem the Public Service Commission (PSC) is requiring 300 MW of demand response in the New York City. Consolidated Edison is to obtain half of that response (150 MW). The other half will come from other suppliers. The PSC has set time lines and metering requirements to help accelerate acceptance. Demand response solutions might get funding from NYSERDA.

NYISO operates three demand response programs: the Emergency Demand Response Program (EDRP), the Installed Capacity Special Case Resources program (ICAP-SCR), and the Day-Ahead Demand Response Program (DADRP). The first two provide the system operator with additional resources to address system emergencies while the third provides voluntary response to power system prices. Smaller loads participate through third party aggregators.

EDRP response is voluntary. Participants are paid at least $500/MWh curtailed (measured hourly) and are provided two hours notice. ICAP-SCR participants receive capacity and performance payments and response is mandatory with 21 hours advanced notice. DADRP allows responsive loads to submit bids of $75/MWh or more for load reductions by 5:00 am the day ahead. These bids compete with generation in the wholesale energy market. Response failure is subject to market penalties. Direct served customers must have hourly interval meters. Other verification methods, such as statistical sampling can be used for aggregated loads.

NYISO had 2000 customers registered to provide 1754 MW of load reduction in February 2005. 1377 MW was in the ERDP/ICAP-SCR reliability programs and 377 MW was in the DADRP economic program. The programs were quite effective in helping to restore the system after the August 2003 blackout.

NYISO is working on allowing responsive load to supply spinning reserve. This will likely occur in the third quarter of 2007. Currently responsive load can only supply non-spinning reserve.

Ancillary service bids are co-optimized with energy requirements by the NYISO allowing the system operator to use ancillary service resources to supply energy if needed. This may be limiting the amount of load response offered to the system since some loads may be unwilling to expose themselves to the risk of being required to curtail operations for an extended period.

3.4.6 ISO-NE

ISO New England (ISO-NE) evolved out of the NEPOOL tight power pool which, prior to 1999, provided joint economic dispatch across Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont. The ISO-NE has over 8000 miles of transmission lines to serve a ~27,000 MW peak load. (ISO-NE 2006)

ISO-NE works with stakeholders to develop fair and efficient wholesale electricity markets, to plan a reliable bulk power system, and to protect the short-term reliability of the control area. ISO-NE annually develops a ten year Regional System Plan which accounts for the addition of generation units, demand response, load growth, and generation retirements. System economics and air emissions are considered along with reliability in planning the transmission system. In addition to specifying what transmission enhancements are required the Regional System Plan also helps attract market solutions (generation and demand response) to mitigate the need for the transmission enhancements. The current Regional System Plan includes 272 transmission projects that are expected to cost between $2 and $4 billion.

Though ISO-NE has a significant demand response program (described below) demand response is not the same as transmission enhancement in ISO-NE’s eyes. Demand response can provide a temporary solution until a permanent transmission enhancement is in place. When the power system in Southwest Connecticut was recognized as being inadequate it was also recognized that neither transmission nor generation solutions could be implemented in time to restore reliability. 250 MW of demand response solutions were sought to quickly fill the reliability gap. Transmission solutions are still being pursued to permanently resolve the problem.

ISO-NE believes it has authority from FERC to order *transmission* construction if that is needed to maintain reliability. Conditions have never warranted that action. Instead the ISO has preferred to identify needs and allow the market to propose generation, transmission, or demand response solutions. The ISO views its role as selecting the best from what is proposed rather than identifying the best solution on its own. Selected projects then move through the state and federal regulatory process to enter the rate base or transmission tariff if they are transmission based. Generation and demand response projects move through their own regulatory and commercial processes.

While ISO-NE does not own demand response resources it does have an active program that provides incentive payments to commercial and industrial customers if they reduce their electricity consumption or operate on-site generation when the power system is stressed or in response to high real-time wholesale electricity prices. Current enrolment exceeds 500 MW. ISO-NE utilizes “Enrolling Participants” – distribution companies, demand response providers, and competitive suppliers – that interface between ISO-NE and customers. Demand response programs tend to be specifically tailored for loads rather than accommodating energy and ancillary service markets to loads’ capabilities and limitations. ISO-NE is concerned that allowing responsive load to directly supply some services (spinning reserve for example) could result in customers using non-spinning emergency generators as the true supply instead of load reduction. Because ISO-NE can not see behind the customer meter the ISO fears it would not be able to distinguish what type of resource was actually responding. ISO-NE feels that characterizing the response itself would not be adequate absent knowing the source.

The Real-Time Demand Response Program is used to respond to power system reliability events and gives customers either 30 minutes or two hours notification to reduce load. Customers are paid at least $500/MWH of response in the 30 minute notification program and $350/MWH in the two hour program though prices can be up to $1000/MWH if the locational price is above the guarantee. Capacity and reserve payments are also made. Response is mandatory. Interestingly ISO-NE guarantees a minimum of two hours of curtailment for each event – useful for assuring adequate payment for loads that incur transition costs but harmful to loads with limitations on their response duration and time-duration rising cost curves such as air conditioning or refrigeration.

The Real-Time Profiled Response Program utilizes aggregations of directly controlled loads and small generators that require 30 minutes or less notification. Five minute metering is not required and statistical sampling may be substituted.

The Real-Time Price Response Program is a voluntary response program restricted to on-peak times when wholesale prices are above $100/MWH. Responding loads do not qualify for capacity payments. The decision to activate the program is typically made late on the day before. A variety of technologies are used to notify the responding loads including e-mail, web sites, pagers, and automated phone calls.

Five minute metering is required for participation in all but the Real-Time Profiled Response Program. Reporting is through the Internet Based Communications System, a low tech option (reporting within 36 hours), or a super low tech option (reporting within three months).

By the end of 2004 approximately 200 customers were participating in various Reliability Response programs. The ISO did not activate the reliability based program in 2004 in response to system stress but a program audit was conducted on August 20. A 46% response rate was achieved with a 350 MW load reduction. Approximately 33% of the loads did not respond, mostly in the Profiled Response Program. Within the Connecticut Zone the response rate was greater than 100%. (Laurita, Yoshimura, Kueck 2005)

ISO-NE’s use of capacity markets designed around generation makes it difficult for responsive loads to fully participate in the ancillary service markets. Forward capacity markets mean that reserve costs are mostly sunk in real time and rational real time offers are expected to clear at $0. Further, ISO-NE utilizes forward reserve auctions, two to five months in advance, to procure ten minute non-spinning reserve and thirty minute operating reserves. These are difficult commitments for responsive loads to make. These markets are designed to satisfy 95% of the reserve requirements and include penalties for failure to respond in real time. Any resource can participate but it must look like a low capacity generator with a high energy price and capable of providing reserves 98% of the time. (DePillis, 2006)

A responsive load can also register as a Dispatchable Asset Related Demand (DARD), in which case it will essentially be treated as a generator. The load can not restrict its response to contingency events; energy and ancillary services are co-optimized based upon the bid response price. Submitting a $999/MWH only partially mitigates the energy deployment risk and also undesirably reduces contingency event deployments. (DePillis, 2006)

3.4.7 SERC

The Southeastern Electric Reliability Council (SERC) assures that transmission planning is coordinated throughout its region which encompasses all or parts of 16 states in the southeastern and central United States. Prior to the recent consolidation of the ten regions into eight SERC was the largest with a peak load of ~165,000 MW. It has 5,057 MW of interruptible load and demand response and 50,000 MW of load shedding capability. SERC does not have a regional policy concerning the use of demand response related to transmission enhancement. That is left to the individual members.

3.5 AN INTERNATIONAL EXAMPLE

In many parts of the world, as in many parts of the US, demand response impacts transmission planning indirectly by impacting expected demand. In the Nordic countries, for example, Nordel regards demand response as a critical to supporting reliability but it does not implement demand response programs itself as this is done by the individual countries. Demand response appears to be more aimed at providing balancing capability than at deferring transmission and distribution investment. (Heffner 2006A) Australia provides a counterpoint.

Australia's National Electricity Market operates the longest interconnected power system in the world – more than 4000 km from Queensland to South Australia. Peak demand is 31,000 MW. Energy prices are typically under A$40/MWh but can go as high as A$10,000/MWh during system emergencies. (Heffner, 2006B) Such a geographically large power system is necessarily dependant on transmission and transmission constraints are not uncommon. A major method for demand response to participate in markets is in support of the deferral of capital expenditure for load-growth related network expansion.

New South Wales enacted a "D Factor" which allows Distribution Network Service Providers to retain capital expenditures avoided through targeting of demand management. The New South Wales DM Code of Practice also requires Distribution Network Service Providers to exhaust demand management as an alternative before undertaking load-driven network expansion.

Utility owned diesel generators have been used in Bromelton (28MW) and Nelson Bay (6MW) Australia for peak load reduction in order to defer construction of 110 kV and 33 kV lines respectively. (Crossley, 2005)

4. EXAMPLE PROJECTS

It was not possible to compile an exhaustive list of projects in which responsive load is having an impact on the need for transmission enhancement. There are too many transmission planning organizations to survey for that to be practical. Also, projects often have multiple impacts. It is difficult to explicitly characterize some projects as to type. The projects presented here were selected because they have characteristics that directly impact the need for transmission enhancement or they provide a reliability resource for use by the system operator which can reduce the dependence on transmission.

4.1 LIPA EDGE

LIPA Edge is a typical peak demand reduction project controlling residential and small commercial air conditioners using modern technology with several innovative features. It is particularly interesting because it has the technical ability to significantly increase its benefits by providing spinning reserves as well as peak load reduction.

Remotely controllable Carrier Comfort Choice thermostats coupled with two-way communication provided by Silicone Energy and Skytel two-way pagers allows the Long Island Power Authority (LIPA) to monitor capability and response as well as to control load reductions. It also enables customers to control their individual thermostats via the Internet, a benefit that motivates participation (LIPA 2002a). Currently controlling 25,000 residential units and 5,000 small commercial units provides 36 MW of peak load reduction. (Marks 2006)

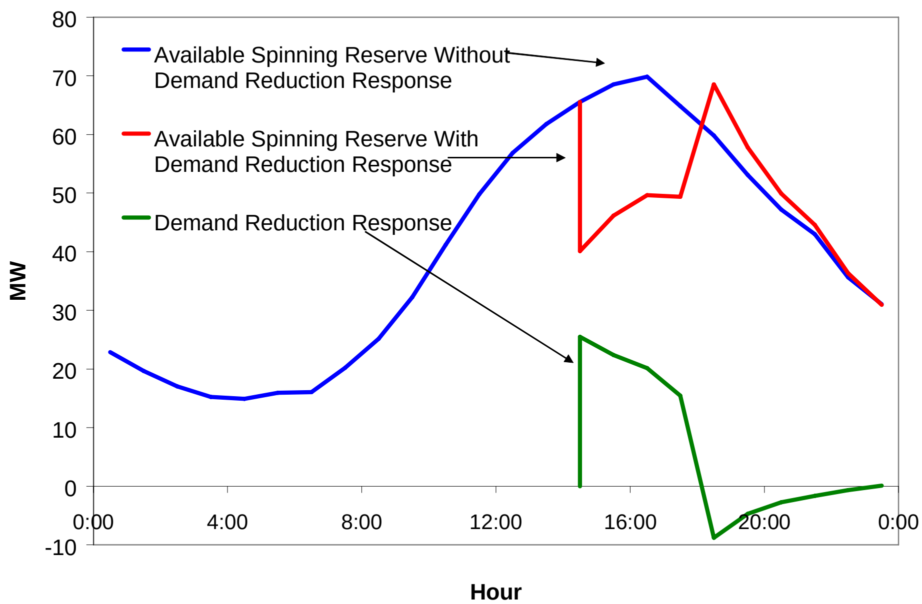

Figure 6 Significant spinning reserve capability remains even when demand reduction is in effect, as shown in this 8/14/2002 curtailment.

Detailed discussions with Carrier in 2002 revealed that the technology is fast enough to provide spinning reserve and provides ample monitoring capability. Further analysis of test data revealed that the program can typically deliver 75 MW of 10-minute spinning reserve (when the peak reduction program only had 25 MW of capacity) at little or no additional cost at times of heavy system loading; this is a significant benefit for capacity-constrained Long Island. Significant spinning reserve capability remains even if the system is being used for peak reduction as shown in Figure 6. (Kirby 2003) Spinning reserve capacity is now likely over 100 MW.

4.2 SCE FEEDER RELIEF

Southern California Edison (SCE), with California Energy Commission support, is conducting a Demand-Response Dispatch Verification Research and Demonstration Project in the summer of 2006 to demonstrate the impacts of distributed resources both as a means to provide specific load relief at the substation and distribution feeder level, and as a spinning reserve resource. The system uses the public Internet, the SCE wide area network and various wireless technologies to provide two-way control and monitoring of the devices that control electric loads at approximately 450 sites in Southern California. Two specific objectives are to demonstrate that when load is curtailed by a dispatch signal, the available MW demand response of a specific circuit can be predicted with a 90% statistical confidence and demonstrate that the load can be curtailed reliably and quickly on the issuance of a dispatch signal. The load shed is expected to start within 10 seconds of the signal and be fully implemented within two minutes.

SCE is implementing a special contract for the test with 400 to 500 residential customers and 50 to 100 commercial customers. Various curtailment intervals are to be tested. The selected circuit has a peak load of 9 MW. SCE expects to curtail 2 to 3 MW depending on time of day, temperature, and day of week. A rigorous statistical analysis has been performed in planning the number of customers under test, the number of tests, and the data acquisition system to ensure the results provide a relative precision of 15% at the 90% level of confidence. SCE expects the test to provide a benchmark for repeatable, precise, rapid demand response used as a reliability service. (SCE 2005)

4.3 XCEL ENERGY PUMPING LOAD

WECC does not currently allow responsive load to supply spinning reserve. Xcel Energy wants to supply a portion of their spinning reserve obligation from their two 124 MW unit Cabin Creek pumped storage plant. Xcel is working with Oak Ridge National Laboratory to develop a test procedure to demonstrate the efficacy of load providing spinning reserve to WECC. Operator directed response will be provided by a fast but conventional shut down of the unit. This is expected to complete in less than one minute – much faster than the 10 minutes allowed for full generation response. The pumps will also instantaneously trip in respond to frequency deviations. The stability runs shown in Figure 3 were made in support of this project.

4.4 ONCOR ELECTRIC DELIVERY COMPANY (TXU)

Oncor offers a Residential and Small Commercial Standard Offer Program in response to a 2002 Texas law requiring a 10% reduction in demand growth. The program consists of incentive payments for the installation of a wide range of energy savings and demand reduction measures. Oncor purchases peak demand reductions from energy efficiency service providers who market and install the measures.

4.5 BPA OLYMPIC PENINSULA

BPA is conducting several pilot projects aimed at deferring the need for transmission enhancements. Several technologies are being utilized including:

- Direct load control – 20 MW from electric water heating, pool pumps, heat pumps, forced air furnaces, and baseboard heating. One way radio pagers and power line communications within the residence are being used.
- Demand response – 16 MW from electric water heaters, cloths dryers, pool pumps, heat pumps, and forced air furnaces. Fiber optic and cable internet connections are being used to communicate with Grid-Friendly™ appliances. Customers can set prices for response. Grid-Friendly™ appliances will also respond to system frequency disturbances.
- Voluntary load curtailment – 22 MW through the Demand Exchange internet-based auction where loads can offer to reduce consumption in response to reliability or market volatility events.
- Distributed generation – 4 MW from industrial and commercial backup generators
- Energy efficiency – 15 MW

4.6 COMMONWEALTH EDISON

As part of the 1992 franchise renewal negotiations Commonwealth Edison agreed to invest $1.25 billion in transmission and distribution improvements and $100 million for the Chicago Energy and Reliability Account program which defers distribution investment by energy efficiency and distributed generation.

4.7 CONSOLIDATED EDISON

Consolidated Edison provides an example where demand response is being explicitly sought as an alternative to transmission and distribution expansion. Consolidated Edison issued a request for proposals in April 2006 seeking at least 123 MW of demand side management in targeted areas of New York City and Westchester County in order to defer transmission and distribution capital investment. Multiple proposals will be considered; each proposal must be for at least 500kW of aggregated peak summer load reduction. Consolidated Edison provided detailed information and maps for each geographic area to help project developers. Materials include:

- Numbers and types of customers (residential, commercial, small commercial, types of business, types of residential, numbers of central air conditioners, numbers of room air conditioners, …)

- Sizes of individual customer loads (10-300+KW)
- Total required load reduction (2-25 MW)
- Need date (2008-2011)
- Minimum project duration (2 to 4 years)

Clean distributed generation may be proposed as well as energy efficiency measures. Distributed generators can reduce customer load but they may not export to the grid to be considered for this program. Energy efficiency measures are allowed (compact florescent lights, energy efficient motors, efficient air conditioning, and steam chillers for example).

Unfortunately, direct load control and measures that "temporarily curtail or interrupt loads" will not be considered. Neither will operating and maintenance improvements nor improved new construction measures. (Consolidated Edison, 2006)

4.8 MAD RIVER VALLEY PROJECT

In 1989 Green Mountain Power (GMP) needed to enhance the distribution system feeding Sugarbush Resort in the Mad River Valley in central Vermont. Load was expected to grow and a $5 million parallel 34.5 kV line was needed. Instead, Sugarbush installed an energy management system to enable it to monitor and control its load and keep the total feeder load below 30 MW. Snowmaking was the major controlled load.

GMP also engaged in an energy efficiency program for other customers on the feeder. GMP largely abandoned the follow-on demand side management work once the network problems were resolved. (Cowart 2001)

4.9 THE ENERGY COALITION

The Energy Coalition was formed in 1981 by end users to aggregate load response to help alleviate generation and network capacity shortages in southern California. The Coalition develops load response capabilities that are sensitive to both the utility needs and the needs of the individual load. Since its inception The Energy Coalition has aggregated loads in the service territories of Pacific Gas & Electric, the Long Island Power Authority, Boston Edison, and Commonwealth Edison.

Interest in the Coalition declined in the 1990s as California went from having electricity shortages to capacity surpluses. Interest revived when the situation turned around again in the 2000s. The Business Energy Coalition is a specific project in the San Francisco area that specializes in short-term network relief. A 10 MW pilot project is based on the area's 200 largest customers with day-ahead and same-day response. Response is limited to five hours/event, one event/day, five events/month, one hundred hours/year. Response can be called upon for CAISO Stage 2 emergencies, spinning reserve shortfalls, forecasted San Francisco temperatures above 78 degrees, local emergencies, and total CAISO load forecast to exceed 43,000 MW.

5. CONCERNS AND OBSTACLES

There are a number of obstacles to the greater use of demand response. Many obstacles are associated with the way power system reliability rules are written and the consequent limitations imposed on load response when used as a resource. Reliability rules are, understandably, often written around the capabilities of the supply resources. There is little point in asking for response that is simply unavailable. This has little adverse impact when there is a uniform pool of resources to draw from and when the resources have little control over their response. It does have an adverse impact, however, when a new type of resources (demand response) tries to enter the mix. When multiple types of resources become available with varying capabilities and limitations the system requirements need to be reevaluated and specified in terms of the basic power system reliability needs rather than in terms of the capabilities of one type of resource. It is particularly important to separate familiarity and comfort with past performance from genuine system requirements.

There are many examples of features of reliability rules that accommodate generator limitations that do not increase system reliability. They are necessary to enable generators to provide the desired reliability response but they are not themselves directly related to that desired reliability response. A partial list includes:

- Minimum run times
- Minimum off times
- Minimum load
- Ramp time for spinning reserve
- Accommodation of inaccurate response
- Limiting regulation range within operating range to accommodate coal pulverizer configuration

It is not that these accommodations should be revoked. They are necessary to elicit the reliability response the power system requires. Similar accommodations should be afforded to other technologies based on their limitations, however. A partial list might include:

- Maximum run time
- Value capacity that is coincident with system load
- Value response speed
- Value response accuracy
- Match metering requirements to resource characteristics

5.1 PERCIEVED TEMPORARY NATURE OF DEMAND RESPONSE

When demand response is considered as an alternative to transmission expansion it is typically considered as *deferral* rather than as an *alternative*. This has important implications for demand response financing as well as performance. Demand response economic viability is determined by comparing the cost of the demand response project with the present value of the savings obtained by delaying construction of the transmission investment for a few years. The transmission alternative, however, is evaluated over a twenty to thirty year facility life. The basic reasoning is that load growth will eventually make the transmission investment necessary so demand response can only delay the inevitable. Operating practice often follows the same temporary logic. Load response programs may be discontinued once the transmission project they have been delaying is finally installed. The excess capacity that is typically initially made available by transmission expansion (discussed below) makes load response, at least temporarily unnecessary.

While this argument that load response is a temporary solution is logical it is quite different from how other transmission investments are evaluated. A subtransmission line might be installed or upgraded delaying the need for a new transmission line for a few years. The subtransmission line would not be taken out of service or out of the rate base, however, once the larger line was in place. It would instead be considered a permanent part of the power system.

These differences result in a lopsided risk equation when comparing projects. When demand response is examined as an alternative to constructing additional transmission it is recognized that load will continue to grow. At some future point the additional transmission will be required. Because of the lumpy nature of transmission additions and their sunk cost that transmission addition will typically obviate the need for the demand response. Consequently the demand response solution can only defer transmission, it can not replace it. A transmission investment is not considered in the same way. If additional transmission is needed later it is *additional* transmission, not replacement. The earlier project is not viewed as a deferral for the latter even if the latter project reduces flows (use) on the earlier.

Three characteristics are fundamental to understanding why demand response is typically evaluated as a short term deferral to long-lived transmission: the "lumpy" nature of transmission, the differences in operating costs structure, and the regulated nature of transmission.

5.1.1 Transmission Investment Is Lumpy

Transmission cost and land use per unit of capacity typically decreases with increasing voltage; unfortunately minimum capacity rises as illustrated by Figure 7. The cost of building a given amount of transmission capacity at 765kV is only one third of the cost of building it at 230kV. The land requirement is less than one fifth. The minimum line capacity of a 765kV line is about ten times that of a 230kV line however. This results in a strong economic incentive to use the highest voltage and install the maximum transmission capacity that is expected to ever be useful. It is often not cost effective to add transmission capacity in small increments; transmission investment is "lumpy".

Demand response solutions do not typically suffer from this lumpy characteristic. It is much easier to install the amount of demand response that is needed now and add more when it is required later. That should be an advantage for demand response when it competes with transmission enhancements. It becomes a disadvantage when demand response can not provide the entire solution.

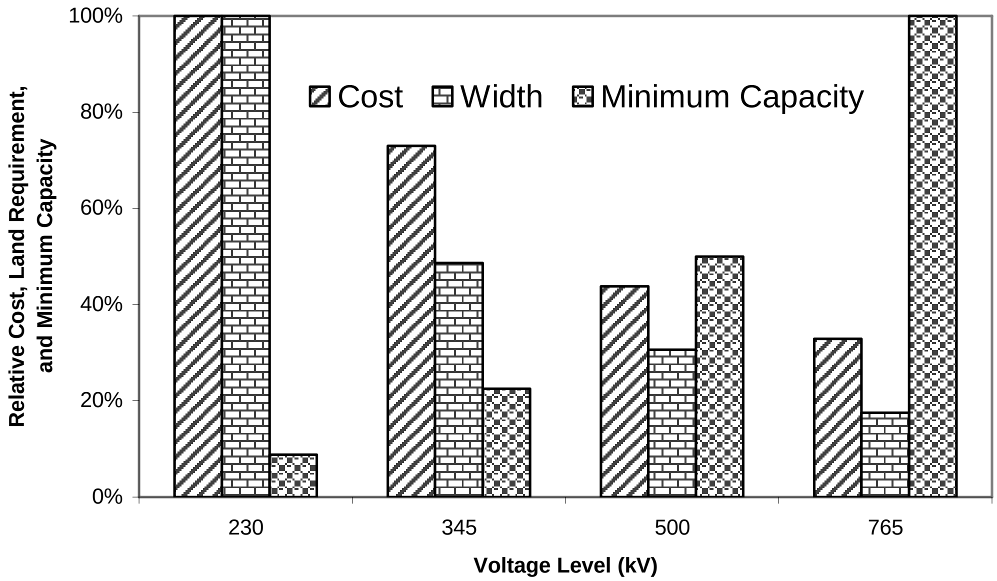

Figure 7 Transmission project cost and land use drops with increasing voltage but minimum size rises.

5.1.2 Operating Costs

The way transmission costs are incurred and paid for is also important. Transmission is a long-lived, capital intensive, low maintenance investment with almost no cost related to use. Once installed, in one sense, use of transmission is free; there appears to be no marginal cost. Conversely, load response typically has costs (or user inconvenience) associated with each use; there is a marginal cost. Consequently, once transmission is available it is used instead of demand response, furthering the idea that demand response is a short lived, high operating cost solution when compared with transmission.

It is true that transmission projects are long lived with essentially no immediate cost for use (other than losses). But demand response is often long lived as well; PEF's demand response program has been operating for over 20 years. While transmission projects have few costs associated with use they do have significant annual maintenance costs; transmission assets deteriorate rapidly with no maintenance (tree trimming, relay and breaker maintenance, etc.). It is difficult to tie specific costs to specific users but the marginal costs are there.

5.1.3 Regulated Vs Competitive Assets

Transmission is almost always a regulated asset. Once it is in the rate base, its costs are fully covered. Responsive load is not usually treated as a regulated capital resource placed in a rate base. Load response may be cheaper overall but once transmission is available transmission always appears to be lower cost. Transmission cost recovery is essentially guaranteed once a project is built. As mentioned above, a 230 kV high voltage transmission line would not be taken out of the rate base when an extra high voltage 765 kV line was overlaid on the transmission system regardless of how line loadings changed.

Reliability regions and ISOs are typically barred from actively developing demand side resources as alternatives to transmission enhancement. Their role is limited to facilitating competitive markets where generators and loads can economically optimize their production and use of energy. Their transmission planning activities identify constraints that are or will be impacting reliability or commerce. Regulated transmission providers and competitive generation and demand entities are expected to offer solutions which the ISO and region assess.

BPA seems to have considered this rational as well. A 2001 BPA consultant report stated: "In many respects these nonwires activities have been outside of TBL's (Transmission Business Line – BPA's transmission side of the business) purview and TBL has had to be passive with respect to them. If they happen, TBL can account for them, but it cannot make them happen." (Orans et al, 2001) BPA changed its approach to transmission planning and now formally considers non-wires alternatives for all transmission enhancement projects costing $2 million or more.

An alternative view would be to treat some kinds of load response as regulated assets that the system operator uses to optimize the operation of the transmission system. Load response would then be like other transmission assets such as capacitor banks and FACTS devices; equipment who's cost is recovered by including it in the rate base or transmission tariff. This might be especially appropriate in cases where the load response is not driven primarily by energy market considerations and where the economic viability of the program is not driven by the loads' opportunity costs. The cost of residential load response providing contingency reserves or peak reduction, for example, is dominated by the cost of communications and control, not by the response payment to the customer. Many customers receive no ongoing compensation. The communications and control could be considered part of the SCADA system and the resource offered to the system operator as one more tool for maximizing transmission performance at minimal cost. Interestingly, involuntary load shedding is treated exactly this way.

5.2 RELIABILITY OF STATISTICAL LOAD RESPONSE

Concern is often expressed that load response is not as reliable or as certain as generation response. While there is no absolute guarantee that any physical resource will be able to provide a specific response at any specific time, large generators have dedicated staff, extensive monitoring and control, and strong economic incentives to actually provide the response they are contracted to provide. Loads, especially small loads, do not have the same staffing or equipment resources. Response is voluntary in some cases. Interestingly there is good reason to believe that the inherent reliability of the response from aggregations of small loads is actually better than the reliability of response from large generators.

Fundamentally, load is a statistical resource while generation is a deterministic resource. Some loads are large and deterministic while some generators are small and statistical; but as a general rule, individual loads are small, are important in aggregate, and behave statistically, while individual generators are large, are important individually, and behave deterministically. There are advantages to both resources and both should be used. The important thing to note is that there are differences. (Kirby, 2003)

Aggregations of small responsive loads can provide greater reliability than fewer numbers of large generators, as illustrated in Figure 8. In this simple example, contingency reserves are being supplied by six generators that can each provide 100 MW of response with 95% reliability. There is a 74% chance that all six generators will respond to a contingency event and a 97% probability that at least five will respond, which implies a nontrivial chance that fewer than five will respond. This can be contrasted to the performance from an aggregation of 1200 responsive loads of 500 kW each with only 90% reliability each. This aggregation typically delivers 540 MW (as opposed to 600 MW) but never delivers less than 520 MW. As this example illustrates, the aggregate load response is much more predictable and the response that the system operator can "count on" is actually greater.

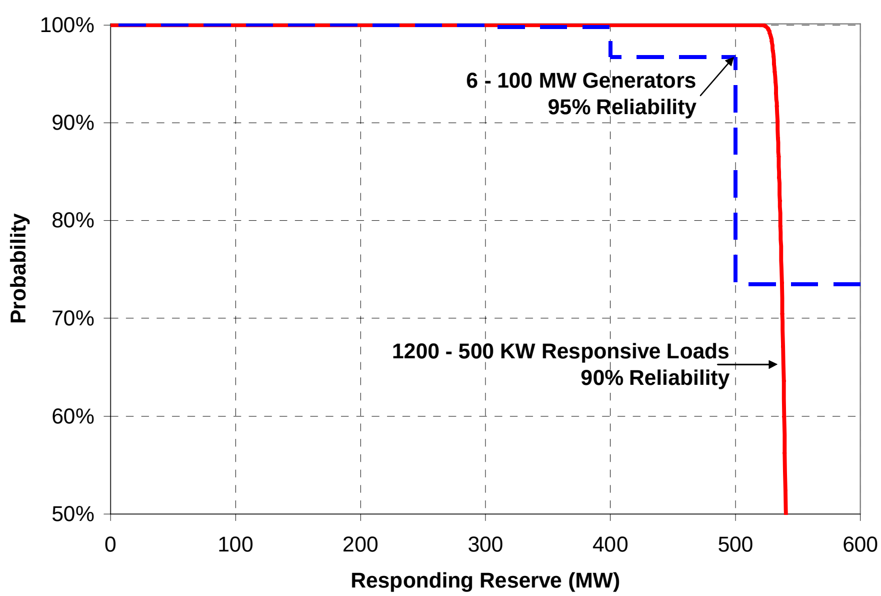

Figure 8 Larger numbers of individually less reliable responsive loads can provide greater aggregate reliability than fewer large generators.

Contingency reserves have historically been provided by large generators that are equipped with supervisory control and data acquisition monitoring equipment that telemeters generator output and various other parameters to the system operator every few seconds. Contingency reserve resources are closely monitored for three reasons: (1) to inform the system operator of the availability of reserves before they are needed, (2) to monitor deployment events in real time so that the system operator can take corrective action in case of a reserve failure, and (3) to monitor individual performance so that compensation motivates future performance. Because the same monitoring system provides all three functions, we often fail to distinguish between these functions. For small loads, it may be better to look at each function separately.

The statistical nature of aggregated load response lends itself to useful forecasting in place of real-time monitoring. Forecasting errors for load-supplied reserves can be more easily accommodated than forecast errors for the total load. A 10% error in the load forecast for a 30,000 MW balancing authority can result in a 3000 MW supply shortfall; a serious operating problem. A 10% error in 600 MW of expected reserve response from responsive load can be handled by derating the resource and calling for 10% more response than is needed. This derating can be refined as experience is gained.

Load response forecasting errors for large aggregations of small responding loads are fortunately correlated with overall load forecasting errors. If total load is higher than the forecast so are available contingency reserves. When available contingency reserves are less than the forecast so is actual load and other generation which was scheduled to serve load is available to provide the reserves.

Metering requirements should be based on the reliability requirements of the system, recognizing that large deterministic resources present a different monitoring requirement than aggregations of small statistical resources in order to achieve the same system reliability.

5.3 MANUAL OVERRIDE AND VOLUNTARY RESPONSE

Load response programs often find that they must accommodate voluntary response in order to increase participation. This is not surprising. While the cost of electricity is important to most consumers it is only one of many costs. Loads often find it impossible to make firm, long-term curtailment commitments because there is some chance that external events (external to the power system) will prevent them from reducing power consumption when requested. Even if a customer is able to respond 99% of the time, the other 1% of the time may be perceived to be of such high importance that the load is unwilling to participate in a curtailment program. This reaction is surprisingly universal; it can be true for residential as well as commercial and industrial customers.[6] Day-ahead and hour-ahead hourly markets reduce or eliminate this problem for many large loads and generators. But the transaction burden of constantly interacting with energy and ancillary service markets is likely too great for many small loads. Many will prefer to establish a standing offer for response that they are able to honor the vast majority of the time.

Manual override provides an alternative with benefits for both the power system and the customer. With a manual override feature, the load curtailment occurs, but the individual customer has the option of overriding the curtailment. The advantage to the power system

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

is that this option increases the load participation and likely reduces the required compensation. The advantage to the customer is that it can opt out of a particular curtailment if the inconvenience or cost for the specific event is unusually high. Many peak reduction programs now include this feature, and it appears to be successful. Most important, the increase in participation outweighs the number of customers overriding the curtailment. How the opt-out is configured can be important.

The natural fear from the power system side is that many customers will always opt out. This is not as large a problem as one might think. Opting out requires the customer to notice that the curtailment is happening and decide that the inconvenience is too great. The customer must take specific action for each event. Customers that chronically opt out could also be dropped from the program. Figure 9 shows the override experience for the LIPA Edge program during peak reduction testing on the afternoon of August 14, 2002 (Kirby 2003). By 3 hours into the curtailment, a significant number of customers were overriding and this must be considered when valuing the program.

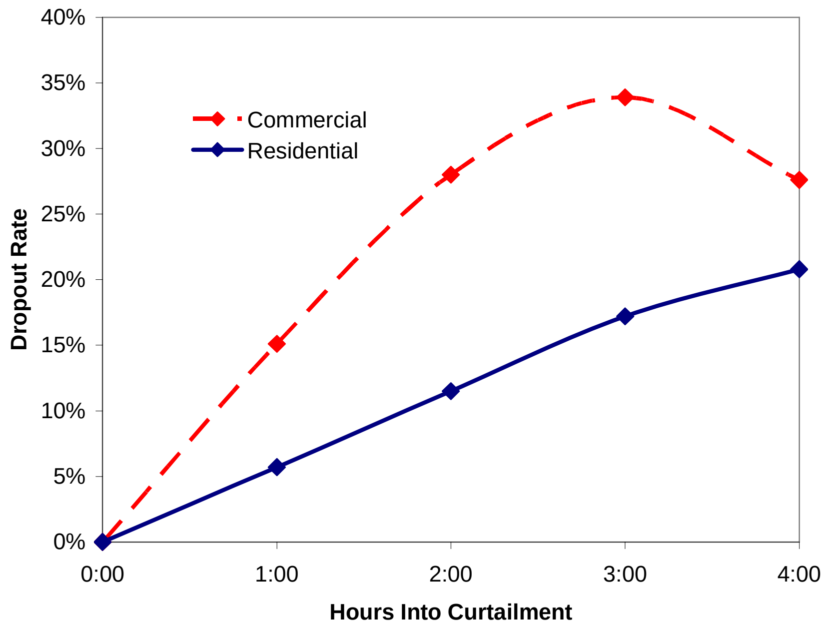

Figure 9 Statistics from the LIPA Edge program show that manual override is not a problem during the spinning reserve time frame.

Manual override is less of a problem when spinning reserve and contingency response is being supplied than when the peak load is being reduced for two reasons. Contingency event duration is shorter and natural human inertia and the slow temperature rise prevents customer response within the typical spinning reserve deployment event. But there is a technical solution as well. Carrier's ComfortChoice responsive thermostats, for example, offer the power system operator the additional option of distinguishing between events that the customer can override and events that the customer cannot. This provides the customer with the ability to opt out of longer demand reduction events while blocking the override during shorter contingency events.

5.4 CAPACITY CREDIT

Demand response programs are sometimes economically disadvantaged in areas with formal capacity markets. Some markets impose an artificial requirement that response must be available 24 hours a day, all season long, for example. This is reasonable when the only source of response is generation whose availability is typically not time variant. Some load is not available to respond in rectangular strips, however. But it is always available when the power system is most heavily loaded and most stressed; at the time of the daily load peak. Figure 10 shows the stack-up of required capacity in real time. Figure 11 shows the coincidence of air conditioning load with total system load, justifying crediting responsive air conditioning with full capacity credit. The ancillary services of regulation, spinning and non-spinning reserve are needed just as much as capacity that is delivering real-power to serve load. Responsive load that is always available at times of system peak should receive full capacity credit.

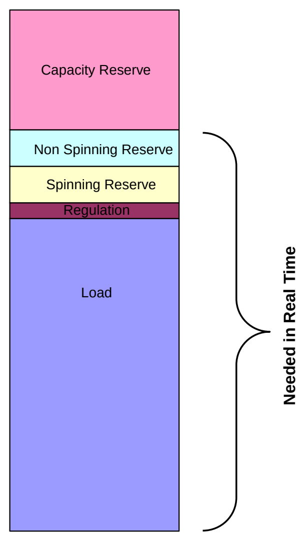

Figure 10 Ancillary services contribute to capacity requirements just as peak load requirements do.

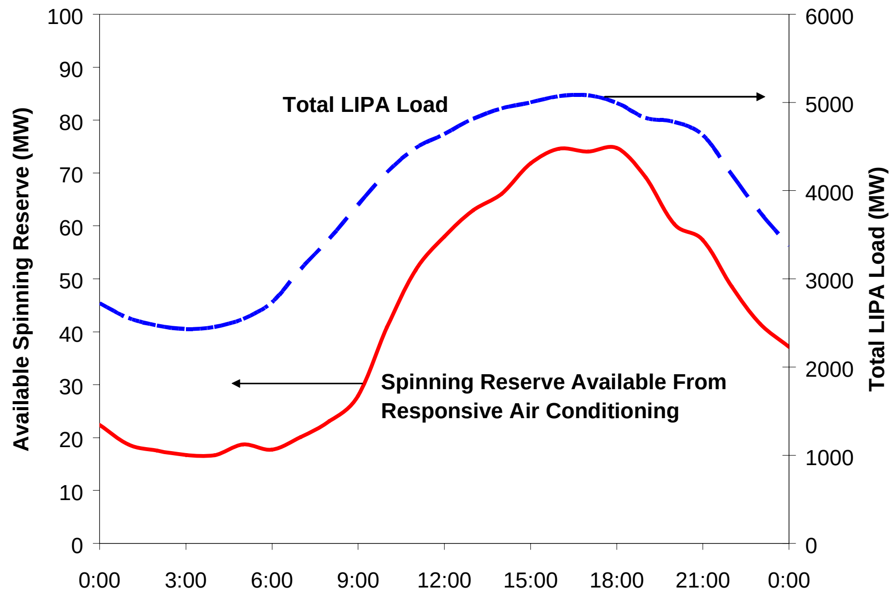

Figure 11 The air-conditioning load matches the total load daily profile, as shown on this Monday, July 29, 2002.

5.5 CO-OPTIMIZATION – RESPONSE COST VS DURATION

Many responsive loads differ from most generators in that the cost of response rises with response duration. An air conditioning load, for example, incurs almost no cost when it provides a ten minute interruption but incurs unacceptable costs when it provides a six hour interruption. Conversely a generator typically incurs startup and shutdown costs even for short responses but only has ongoing fuel costs associated with its response duration. In fact, many generators have minimum run times and minimum shutdown times. This low-cost-for-short-duration-response (coupled with fast response speed) makes some responsive loads ideal for providing spinning reserve but less well suited for providing energy response or peak reduction.

Unfortunately current market rules in New York and New England let the ISOs dispatch capacity assigned to reserves for economic reasons as well as reliability purposes. As long as the ISO has enough spinning and non-spinning reserve capacity to cover contingencies, it will dispatch any remaining resources economically regardless of whether that capacity is labeled as contingency reserve or not. Ancillary service and energy suppliers are automatically co-optimized.

This policy works well for most generators but causes severe problems for loads that need to limit the duration or frequency of their response to occasional contingency conditions.[7] Loads can submit very high energy bids in an attempt to be the last resource called but this is still no guarantee that they will not be used as a multi-hour energy

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[7] Co-optimization often does not work for energy or emissions limited generators either.

resource. Submitting a high cost energy bid also means that the load will be used less frequently for contingency response than is economically optimal. Price caps on energy bids further limit the ability of the loads to control how long they are deployed for.

California had this problem with their rational buyer but changed their market rules and now allows resources to flag themselves as available for contingency response only. PJM allows resources to establish different prices for each service and energy providing a partial solution. ERCOT does not have the problem because energy is supplied through bilateral arrangements that the ISO is not part of. Energy and ancillary service markets are separate. Possibly as a consequence half of ERCOT's contingency response comes from responsive load.

5.6 CHICKENS AND EGGS

Reliability rules and market structures are complex and in some ways delicate. This is more true in the competitive market environment of today than it was in the vertically integrated environment of the past. Market participants will, quite rightly, carefully analyze the rules and behave in whatever manner maximizes their profits within those rules. System reliability can be jeopardized if poorly thought out rules are put in place. Consequently market designers and reliability engineers are cautious about changing rules without good cause lest those changes have unintended consequences.

Reluctance to change rules can adversely impact new technologies and generate a chicken-or-egg problem. Technologies that are blocked from the market by current rules can not develop. Undeveloped technologies do not represent sufficient market force to warrant changing the rules to accommodate them. This is especially true for load response technologies which often require cooperation among a large number of entities. A load aggregator can not interest loads in being responsive until the rules allow the specific response and state what is required to provide it. Market designers will not consider changing market rules to accommodate load response technologies until they clearly see that there are sufficient MWs of response to make the effort worthwhile. Aggregators will not invest in response technology until the rules are clear and the loads are willing to respond.

Testing new technologies is more difficult in the new restructured environment as well. Most ISOs do not have research budgets. It is very difficult for them to decide to conduct a limited test on a new technology. Their market rules are developed through large, slow consensus processes. Any test has to be agreed upon through the same slow, deliberative process. Simply allocating the cost of a test is often contentious and prevents progress.

5.6.1 Demand Response Portfolio Standard

Phil Giudice of EnerNOC proposed a Demand Response Portfolio Standard at FERC's January 25, 2006 Technical Conference on Demand Response and Advanced Metering. The proposal is interesting for several reasons. Potentially this could help resolve the process problem where no infrastructure exists within the transmission planning process to fully examine the range of possible demand response solutions which might address a system need. It would get around the chicken-and-egg problem that there seems to be no justification for examining demand response because little exists and little exists because no opportunity is perceived.

This idea is slightly different than a Renewables Portfolio Standard where the primary benefit is to help the technology develop. Here the primary focus would be on helping the system operators get comfortable with the reliability response and working through the analysis capability problems. In both cases the program would help the technology get further along the declining cost curve, and partially account for externality benefits that are not captured through normal market payments.

The idea is actually not so different from what is done today for load shedding. There is a reliability requirement established by NERC and the regional councils for explicit amounts of automatic load shedding. Load shedding is not "allowed to compete with other offered solutions". It is simply required because we know it is needed in the mix in order to assure reliability.

6. CONCLUSIONS AND RECOMENDATIONS

Assessing whether demand resources are treated equitably in regional transmission expansion planning does not result in a definitive answer. Responsive load is an important though underutilized reliability resource for the North American power system. There is approximately 22,000 MW of interruptible load and DSM which represents roughly 3% of the peak load; large enough to be “real” but still relatively small. A full third of the total load, 270,000 MW, is used as a responsive-resource-of-last-resort to prevent cascading blackouts; a very large but largely unrecognized resource. Both of these resources are factored into transmission enhancement planning either explicitly or implicitly as modifiers to the load forecast in most regions (FRCC is an exception). Loads also supply some ancillary services and efforts are underway to allow them to supply more. Conversely, explicit use of load response as an alternative to transmission expansion is extremely rare.

Most regional organizations state that they do not implement transmission enhancement solutions, they simply identify problems. It is the responsibility of transmission, generation, and demand response providers to offer solutions which the reliability organization evaluates for reliability and economic performance. The region or ISO selects the best solutions from those offered and endorses that selection to state and federal regulators. Construction and implementation is the responsibility of the proposer. If there are few demand response solutions implemented, they reason, it is because the competitive market has not offered or selected them. When viewed in that light demand response is treated equitably.

Requirements do exist in some regions to explicitly consider demand response alternatives when proposing transmission enhancement projects (BPA and MISO, for example) but this has not yet resulted in significant demand response projects being implemented.

In other ways demand response is severely disadvantaged. Demand response solutions are treated differently than transmission solutions when evaluating the need for transmission enhancement. Demand response solutions are typically not sought with the active, meticulous, accommodating effort that is applied to transmission and generation solutions. Transmission is treated as a permanent regulated solution while load response is treated as a temporary competitive solution. Demand response solutions are also treated differently than generation. Generator characteristics like minimum run time are accommodated in market and reliability rules but load response characteristics like statistical response are not.

6.1 STEPS FOR ASSURING EQUITABLE TREATMENT OF DEMAND RESOURCES

Several things can be done to obtain increased access to this under utilized reliability resource:

- Require specific consideration of demand response alternatives for all transmission enhancement proposals.
    - Require demand response evaluations early enough in the process so that demand response solutions can actually be developed.
    - Require reporting of alternatives considered and reasons for decisions.
    - Consider requiring demand management to be fully utilized before transmission and distribution enhancements are allowed.
- Assure that requirements are specified in terms of functional needs rather than in terms of the technology that is expected to fill the need. This applies to ancillary services as well as to transmission enhancement.
    - Value response speed and accuracy.
    - Value statistical response.
- Accommodate the inherent characteristics of demand response resources (just as generation resource characteristics are accommodated).
    - Recognize that some responsive loads have maximum run times
    - Recognize the statistical nature of demand response from aggregations of numerous small loads.
    - Recognize that the monitoring and communications requirements to maintain system reliability are fundamentally different for aggregations of large numbers of small resources than they are for fewer large resources.
    - Recognize the coincidence of demand response capability and total system load. Allocate appropriate capacity credit to demand response.
    - Accommodate voluntary response and perform the research required to establish the level of reliable response capability.
- Enable a mechanism that allows regional organizations to test new technologies without having to first permanently restructure markets. Include a mechanism to fund such tests.
- Consider treating some demand response resources as regulated transmission assets available for reliability response rather than as competitive entities acting in the energy markets.
- Assure that co-optimizers properly recognize the capabilities and characteristics of demand resources. Do not let them force entities to provide services they are not capable of providing.
- Allow appropriately responsive load to provide all ancillary services including spinning reserve, regulation, and any new frequency responsive reserves.
- When appropriate, treat demand response as a permanent solution, similar to transmission enhancement.
- Require regional reliability organizations to actively solicit demand response.
- Allow all loads access to real-time-prices.
- Encourage real-time-metering and advanced metering infrastructure.
- Develop better load response forecasting tools for system operators to increase the usefulness and acceptability of demand response.
- Consider shielding transmission and distribution companies from losses when they encourage demand response programs.

- Consider establishing a minimum percentage of demand response projects, similar to a renewables portfolio standard.

More can be done to integrate demand response options into transmission expansion planning. Given the societal benefits it may be appropriate for independent transmission planning organizations to take a more proactive role in drawing demand response alternatives into the resource mix. Existing demand response programs provide a technical basis to build from. Regulatory and market obstacles will have to be overcome if demand response alternatives are to be routinely considered in transmission expansion planning.

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