Demand-Side Management Influence on Reliability

RESULTS AND RECOMMENDATIONS

September 2007

Demand-Side Management Task Force

Of the

Resource Issues Subcommittee

North American Electric Reliability Corporation

Demand-Side Management Task Force

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Introduction

Demand-Side Management (DSM) is important ingredient of an overall portfolio of resources required to meet the increasing demands for electricity in North America1. DSM is often understood to include two components: energy efficiency (EE) and demand response (DR). EE is designed to reduce electricity consumption during all hours of the year, attempting to permanently reduce the demand for energy in interval ranging from seasons to years and concentrates on end-use energy solutions. DR, on the other hand, is designed to change on-site demand for energy in intervals from minutes to hours and associated timing of electric demand/energy use (lowering during peak periods) by transmitting changes in prices, load control signals or incentives to end-users reflecting production and delivery costs.

DSM resources lead to reductions in supply-side and transmission requirements to meet total internal demand[2]. They should be considered in long term planning exercises as a supplement to long-term planning reserves, and provide operational reliability through operating reserves and flexibility. DSM resources can also be used to manage the risk associated with construction and operations of traditional supply-side resources as well as a variety of new operating characteristics associated with intermittent renewable resources. NERC's 2006 Long-term Reliability Assessment (LTRA) noted:

> *Demand reductions have been achieved through various demand response programs. Direct control load management and interruptible demand programs represent about 2.5 percent of summer peak demand (20,000 MW) in the U.S. and about 2.5 percent of winter peak demand (2,500 MW) in Canada. New or expanded demand response programs and initiatives can further reduce peak demands.*

The 2006 LTRA also concluded:

> *Long-term electricity supply adequacy requires a broad and balanced portfolio of generation and fuel types, transmission, demand response, renewables, and distributed generation; all supply-side and demand-side options need to be available.*

As the industry's use of Demand-Side Management evolves, NERC's data collection and reliability assessment will change highlighting programs and demand-side service offerings that have an impact on bulk system reliability. Figure 1 provides a graphic illustration of

[1] ISO/RTO Council, , "Harnessing the Power of Demand: How ISOs and RTOs Are Integrating Demand Response into Wholesale Electricity Markets," http://www.isorto.org/site/c.jhKQIZPBImE/b.2604461/k.F287/Documents.htm, October 2007

[2] See Appendix IV Glossary for definitions of terms used in this report.

DSM categories defined by NERC's Demand-Side Management Task Force (DSMTF). Though the categories differ somewhat from those described in FERC's report[3], they focus exclusively on supporting data collection and analysis measuring bulk system reliability.

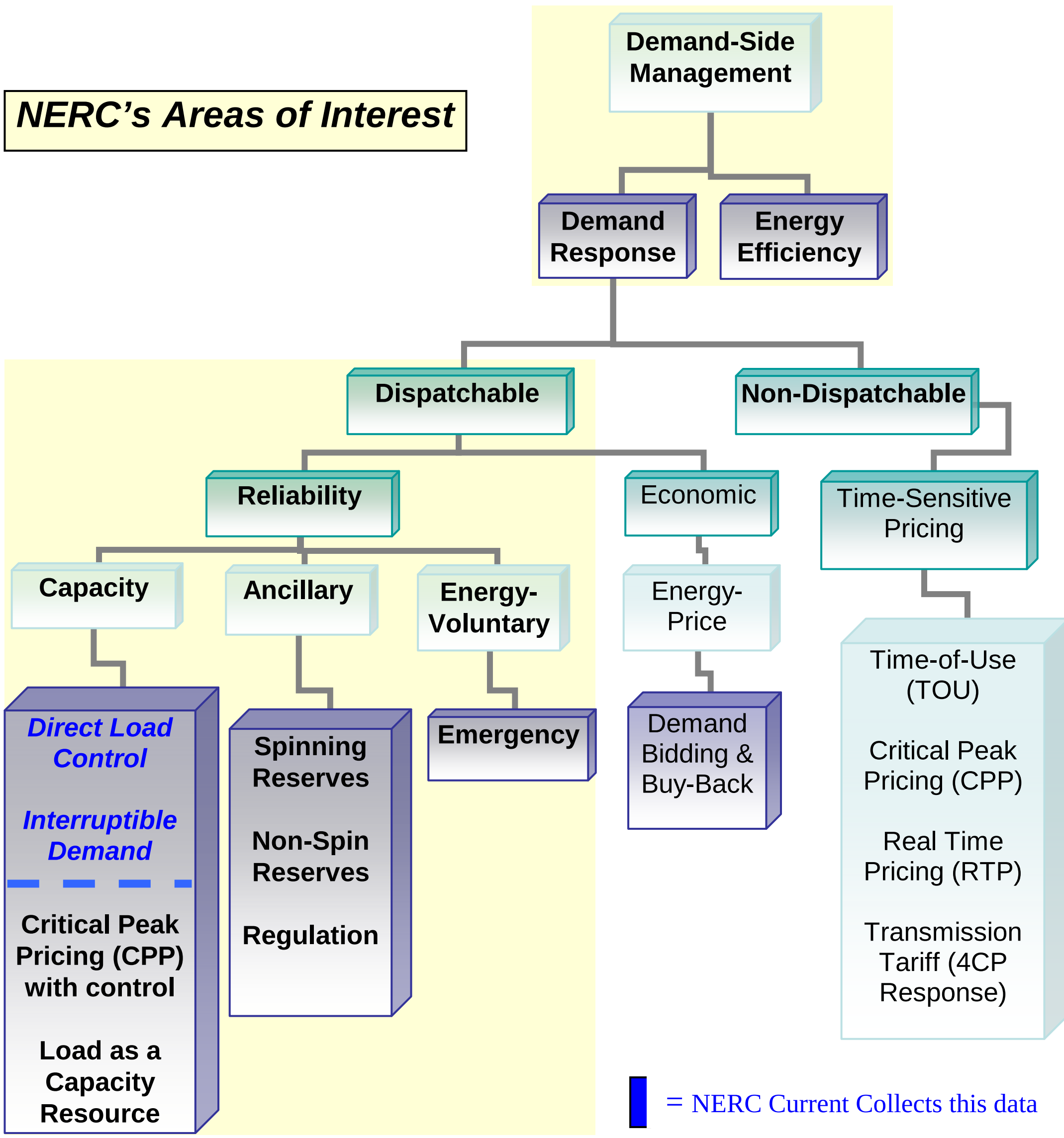


Figure 1: Demand Response Programs and NERC's Data Collection

[3] FERC Staff August 2006 Report: "Assessment of Demand Response & Advanced Metering" Chapter IV, Existing Demand Response Programs and Time-Based Rates. http://www.ferc.gov/legal/staff-reports/demand-response.pdf

NERC's seasonal and long-term reliability assessments currently assume EE programs are netted from Internal Demand forecasts. Internal Demand includes adjustments for utility indirect demand response programs such as conservation programs, improvements in efficiency of electric energy use, rate incentives, and rebates.

However, the results of a recent Load Forecasting Working Group Survey indicated that the impact of future EE is implicitly included by the majority of regions/subregional entities, though a nearly equal number indicate EE is not reflected in their forecasts. In addition, new state-specific energy efficiency portfolio standards, the re-birth of integrated resource planning, and new EE legislation all indicate that DSM is likely to have a more prominent role in future resource planning activities than in the past.

NERC collects specific information about two demand response varieties: Interruptible Demand[2] and Direct Control Load Management[4], both directly controlled by the operator. The Total Internal Demand[5] is reduced by the sum of Interruptible Demand and Direct Control Load Management obtaining the Net Internal Demand[6].

Merely tallying up the amount of energy efficiency or demand response capability at the time of peak demand does not address DSM's influence on the reliability of the system. The calculation of the amount of reserve MW at the time of system peak may not provide an indication of the capacity, or load relief, that will be available at different portions of the summer peak cycle or throughout the entire year to meet customer requirements.

Three categorizations (denoted with *) were developed for investigation of additional types of DR and Energy Efficiency as part of the DSMTF activities (see Appendix 1 for the Task Force Charter):

1. Energy Efficiency (EE)*
2. Demand Response (DR)
    a. Incentive-Based (IBDR)*
    b. Time-Based (TBDR)*

NERC's Standards support the collection and analysis of DSM especially MOD-016-0 through MOD-021-0[7].

[4] See NERC's Glossary: ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May07.pdf

[5] Total Internal Demand equals the sum of the Internal Demand and the Standby Demand

[6] Net Internal Demand equals the Total Internal Demand reduced by Direct Control Load Management and Interruptible Demand.

[7] ftp://www.nerc.com/pub/sys/all_updl/standards/rs/MOD-016-1.pdf,
ftp://www.nerc.com/pub/sys/all_updl/standards/rs/MOD-017-0.pdf,
ftp://www.nerc.com/pub/sys/all_updl/standards/rs/MOD-018-0.pdf,

The steps going forward are to:

1. Develop metrics which measure the influence of DSM on bulk electric system reliability from two perspectives:
   a) Historical performance
   b) Forecast
2. Identify the data requirements to support metric development
3. Make recommendations to the Resource Issues Subcommittee (RIS) on metrics and data collection (historic and for reliability assessments).
4. Upon acceptance from RIS and the NERC Planning Committee, develop data collection templates to measure historic performance and advise the Reliability Assessment Subcommittee on data collection requirements for reliability assessments. If required, develop a Data Authorization Request (DAR) to obtain industry input to the data collection and metric development.

The goal of this report is to:

1. Present Metrics for the aforementioned categories of DSM influencing reliability
2. Identify Data Requirements that support metric development
3. Develop recommendations about the about historic performance and seasonal and long-term reliability assessment data collection

ftp://www.nerc.com/pub/sys/all_updl/standards/rs/MOD-019-0.pdf,
ftp://www.nerc.com/pub/sys/all_updl/standards/rs/MOD-020-0.pdf,
ftp://www.nerc.com/pub/sys/all_updl/standards/rs/MOD-021-0.pdf

Energy Efficiency

The benefits and characteristics of EE have been well studied and documented.[8] In addition to energy savings, EE may reduce peak demand and defer the need for new investments.

Databases exist such as California's Database of Energy Efficiency Resources ("DEER") providing both energy and capacity values for thousands of energy efficiency measures. However, there are a variety of ways for energy efficiency to be measured. The most straightforward method is to use the expected, or average, impact. In some cases, a more conservative measure may be used de-rating energy efficiency impacts for uncertainty in load reduction (the "dependable" reductions). Successful integration of energy efficiency into resource planning requires close coordination between those responsible for energy efficiency and those in bulk system planning to ensure appropriate capacity values are estimated while meeting reliability objectives.

NERC currently obtains forecast internal demand data for summer/winter peaks. Determining the effects of energy efficiency on peak internal demand can provide a measure of reliability benefits. Energy efficiency programs and their results have been well studied and documented.[9]

Understanding Energy Efficiency

To incorporate energy efficiency into resource planning, the energy efficiency peak demand reduction must be defined so resource planners can evaluate it along with capacity resources. Care must be exercised, to assure that the estimates are not misused for other applications. For example, a peak value may be developed for a transmission study based on the energy efficiency reduction during the 12 monthly peaks, but then misused in a generation planning application with a single annual peak.

Analysts can use the same engineering or statistical models developed for producing energy reduction estimates (assuming that the model has sufficient hourly information to match the peak definitions). It is incorrect to assume the largest demand reduction from an energy efficiency measure occurs during peak demand. The coincident peak reduction is generally lower than the non-coincident peak reduction:

1. The timing of the largest reduction does not match the timing of the utility peak,
2. Not all measures will be operating at the time of the peak (people are not home), and
3. Equipment not installed or maintained properly.

In addition, there are synergistic affects that can increase or decrease the reductions depending upon other energy efficiency measures.

Percentage energy savings is not the same as percentage demand savings. For example, in California, SEER was used as the primary measure of AC unit efficiency. Codes and standards were written to promote high SEER units in the state, with the untested expectation that the more efficient unit would also help reduce capacity needs. Many manufacturers responded to the SEER metric with high SEER units that had two compressors and may result in a higher peak demand.

[8] Department of Energy, "National Action Plan for Energy Efficiency," July 2006. http://www.epa.gov/cleanenergy/pdf/napee/napee_report.pdf
[9] Department of Energy, "National Action Plan for Energy Efficiency," July 2006.

Different energy efficiency programs (industrial, commercial and residential) may have variable influence on for total capacity (MW) reduction depending on the time of day reduction is desired. Load forecasting is a critical component to understand the overall peak reduction observed or expected. Tracking and validating energy efficiency programs is vital to increase the accuracy of forecasts.

For NERC to seriously consider the reliability benefits of EE, the resources promised by energy efficiency programs must be reconciled (measurement/validation) on a historical basis with projections. Once this validation occurs, NERC proposes to modify Total Internal Demand with projections.

1. Historic Data Collection

   Two factors should be considered:

   1. Amount of peak-demand reductions caused by energy efficiency
   2. Estimating the probability the reduction will occur during the peak

   DSMTF recommends historical data collection for reconciled EE (measured/validated) compared to projected EE.

2. Forecast Internal Demand

   From the bulk electric system reliability perspective, understanding and quantifying the MW reduction on-peak for both a 50/50 forecast is vital to perform seasonal and long-term reliability assessments. Currently, NERC collects internal demand forecasts with energy efficiency netted.

   DSMTF recommends NERC augment their current collection of internal demand to collect energy efficiency in those cases where it has been estimate:

   1) *Expected Annual MWh Saved/Net Energy for Load*
   2) *Summer & Winter MW Expected Reduction at time of peak internal demand for a 50/50 forecast*

http://www.epa.gov/cleanenergy/pdf/napee/napee_report.pdf

Demand Response

DR programs have been in use for many years, providing more direct control to system operators. In addition, high performance factors are emerging from demand response providers not using direct control methods. The influence of DR on reliability concentrates on peak demand reduction, periods of high wholesale prices, or low-reserve conditions rather than on reductions in overall energy consumption.

Long-term reliability benefits include reduced supply-side and transmission requirements at time of peak or other times when resource availability is reduced. Additionally, DR supports the management of operational reserves/flexibility as well as long-term planning reserves.

All DR resources may benefit overall system reliability, though some DR options benefit system reliability more than others. The most dependable DR are incentive-based provided by load resources under contractual obligation to perform, subject to dispatch by grid operators, and meet measurement & verification standards consistent with their importance to grid reliability. Some DR options can have more reliability benefits than conventional supply-side peaking resources such as a combustion turbine generators ("CTG"). The reliability benefits of DR are a function of, among other things, any limits on annual interruptions, the frequency of interruptions, the duration of interruptions, the ramp-up time to reduce load, and penalties or sanctions for non-performance.

Many large end-users have the necessary metering and telemetry equipment capable of providing demand response for many years. The cost of advanced metering and telemetry does not appear to be a significant barrier to increasing their participation; rather, DR design an extremely important consideration when decisions for investments are made. Expanding DR programs to smaller customers may require substantial investment in technologies to assure adequate measurement and verification of the load response, including advanced metering, load curtailment technologies, two-way customer communications. Such investments must be recognized along-side other investments as part of overall bulk power system rejuvenation.

Increased predictability of customer participation and load response, especially for voluntary programs, is vital to understand the influence of DR on reliability. DR programs are further classified as either Incentive-based (IBDR) or Price-based (PBDR).

Incentive-Based Demand Response (IBDR)

IVDR includes an inducement or incentive for customer participation and peak load reductions, typically in the form of a capacity payment. They provide an active tool for load-serving entities, electric utilities or grid operators to manage their costs and maintain operational reliability. IBDR have been used for many years, increasing direct control to system operators and can provide capacity, ancillary services and energy with a high degree of certainty. NERC collects Demand Control Load Management and Interruptible Demand as part of its seasonal and long-term reliability assessments.

The following categories[10] of IBDR were considered as part of the DSMTF effort:

- Contractual Obligated
    1) Direct Control Load Management
    2) Interruptible Demand
    3) Emergency Demand Response
    4) Ancillary/Operating Reserve
- Discretionary
    1) Load Reduction Acting as Capacity
    2) Demand Bidding & Buy-Back
    3) Emergency Demand Response

The DSMTF recommendation for data collection on Demand Response programs includes both ongoing/historic performance to support industry analysis of the influence of IBDR on reliability and changes to internal demand data collected by NERC for seasonal and long-term reliability analysis.

1. IBDR Historic Data Collection

   The metrics and supporting data requirements are found in Appendix III.

2. IBDR Forecast Internal Demand Data

   Load forecast information should be provided to NERC for its Seasonal and Long-Term Reliability Assessment should provide data on IBDR for those programs deployed and for all categories.

Time-Based Demand Response (TBDR)

TBDR link prices in retail and wholesale markets. Retail consumers obtain a price signal reflecting the costs of production and delivery providing a signal to deploy resources more efficiently. This characteristic, as TBDR is generally tailored for mass markets, has the potential to reduce or shape electricity use and overall costs.

[10] See Appendix IV for Definitions

Voluntary demand response triggered by high energy prices can have reliability benefits if energy prices can predictably correlate to scarcity conditions or grid disturbances. Similarly, in cases where customers' delivery charges are based on their consumption during system peaks, economic demand response actions taken to lower these charges can have direct and positive impacts on reliability. Such price-based demand response is often undertaken unilaterally by customers — that is, not subject to operator dispatch and potentially taken without the involvement or knowledge of the load-serving entity. Without ongoing measurement and verification, effort to measure the quantity and quality of the reliability benefits of price-based DR becomes complicated.

The DSMTF recommends data collection on Demand Response programs includes both ongoing/historic performance to support industry analysis of the influence of TBDR on reliability and changes to internal demand data collected by NERC for seasonal and long-term reliability analysis.

1. TBDR Historic Metrics & Data

   The metrics and supporting data requirements are found in Appendix III

2. TBDR Forecast Internal Demand Data

   Load forecast information provided to NERC for its Seasonal and Long-Term Reliability Assessment should not total time-based demand response (TBDR) programs directly into internal demand forecasts. Projected seasonal and long-term TBDR forecast demand data should be explicitly provided, considered *Energy-Only* (no reduction of Internal Demand), and should include, when possible, all the following TBDR programs:

   1) Time of Use (TOU)
   2) Critical Peak Pricing (CPP)
   3) Real-Time Pricing (RTP)

Conclusions and Recommendations

To support industry analysis of the influence of demand side management programs on reliability for the Seasonal and Long-Term Reliability Assessments, the DSMTF recommends NERC:

- *Energy Efficiency:*
  - *Collect energy efficiency historical data with an emphasis on documentation pertaining to the methodology for estimating the peak capacity component of the energy efficiency portfolio.*
  - *Augment the current collection of internal demand to collect data forecasting the effect of energy efficiency, where it has been estimated and measured:*
    - *Annual MWh Saved/Net Energy to Load*
    - *Summer & Winter MW Reduction at time of peak internal demand (50/50) forecast.*
  - *Augment the current collection of internal demand to collect data forecasting the effect of energy efficiency programs on peak demand, where it has been estimated and measured:*
    - *Annual MWh Saved/Net Energy to Load*
    - *Summer & Winter MW Reduction at time of peak internal demand (50/50) forecast.*

- *Demand Response*
  - *Data collection on Incentive-based demand response should include both forecast/historic performance.*
  - *Data collection on Time-based demand response should include both forecast/ historic performance.*

Appendix I

Planning & Operating Committee

Joint Task Force

Demand Side Management Influence on Reliability Task Force (DSMTF)

Purpose

The goal of this Joint Task Force is to evaluate and provide recommendations to the OC and PC regarding the appropriate reflection of Demand Side Management (DSM) in both long-term reliability assessments and short-term operations arenas. The JTF will provide recommendations about improvements, if any, to NERC's Reliability Assessment to better reflect the reliability impacts, and provide a basis for enhancements in the operational integration for reliability purposes. The scope of this JTF is DSM, encompassing both Demand Response and Energy Efficiency arenas.

Tasks:

The task force will:

1. Review Current Data Collection methods.

i. Review existing NERC Standards (especially MOD-016-0 through MOD-021-0) to develop a survey template for collection of DSM reliability impact results data based on the current standards: MOD-21 "Accounting Methodology for Effects of Controllable DSM in Forecasts" which uses the data reporting procedures from MOD-16-0_R1. "Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy Load and Controllable Demand-Side Management."

ii. Using data collected, determine the amount and type of forecasted DSM by Load-Serving Entity and by DSM type. Categorize the information collected by region as well as by ISO/RTO markets.

iii. Review Current Industry Data Collection Programs:

(a) Energy Information Administration (EIA)

(b) Database for Energy Efficiency Resources or DEER (California Energy Commission)

(c) Regional, ISO/RTO, Curtailment Service Providers, industry organizations and LSEs

(d) NAESB

(e) IEEE

(f) IEA

iv. Provide recommendations on the measurement of reliability impacts (planning and operation horizons) using existing data collections and provide recommendations for enhancements to data collection requirements.

2. Review Energy Efficiency influence on reliability

i. Review data-based impacts on reliability of energy efficiency initiatives.

ii. Provide recommendations on measuring and integrating reliability impacts on planning and operating horizons.

3. Evaluate existing DSM reliability performance metrics and their relevance to planning and operation horizons, and provide appropriate recommendations.

4. Discussion and summary of the above tasks will be integrated into a White Paper addressing the following areas: a) summarize current data collection methods and proposed enhancements, b) discussion and recommendations about reflecting the reliability impacts in both planning and operational horizons, c) proposals regarding enhancements to reliability impact measures, d) discussion about the foundation requirements for potential reliability standards reflecting DSM, and e) recommendations for further DSM reliability efforts.

5. The White Paper and Proposals will be reviewed with the Resource Issues Subcommittee, and submitted to the Operating & Planning Committee at their December 3-4, 2007 meeting for consideration.

Background

Demand Side Management (DSM) programs are increasingly deployed within the electric utility industry in meeting the growing demand for electricity in North America, which can be used to balance the risks of supply-side options. Demand Response (DR) is a subset of the broader category of end-use customer energy solutions known as Demand-Side Management (DSM). In addition to Demand Response, DSM includes energy efficiency (EE) programs. While the long-term reliability characteristics include reducing supply-side and transmission requirements to meet internal demand, it also can be considered a resource that supplements long-term planning reserves, and provide operational reliability through operating reserves and flexibility.

The NERC Defines Demand-Side Management as:

"The term for all activities or programs undertaken by Load-Serving Entity or its customers to influence the amount or timing of electricity they use[11].

NERC current data collection involves two quantities: 1) on-peak megawatts (MW) for Seasonal (Biannual for Summer & Winter) and 2) Long-Term (10 years) Reliability Assessment Reports: Direct Control Load Management and Interruptible Demand12.

At the June 10-11, 2007 meeting of the NERC Planning Committee, the Resource Issues Subcommittee was asked to lead a joint task force. This Task force will review the reliability implications of DSM on Resource Planning, including the Long-Term Planning Horizon and Operations/Operational/Planning. They will do this by gathering industry experience and obtaining existing empirical results. They will formulate proposals for enhancing the data collection needs and the reliability impact integration of DSM into both planning and operating arenas.

Membership

Membership consists of five industry experts, with the Chair a member of the Resource Issues Subcommittee of the Planning Committee, with remaining members provided by the respective Planning and Operating Committees, including subcommittees or other industry experts. The Operating Committee will be requested for advice once the planning issues have been addressed, and the support of NERC staff will be solicited.

Reporting

Task Force is responsible to the NERC Resource Issues Subcommittee of the Planning Committee.

11 See NERC Glossary, ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May07.pdf
12 See NERC Glossary, ftp://www.nerc.com/pub/sys/all_updl/standards/rs/Glossary_02May07.pdf

Appendix II

Incentive-Based Demand Response
Case Studies

PJM's Load Management program

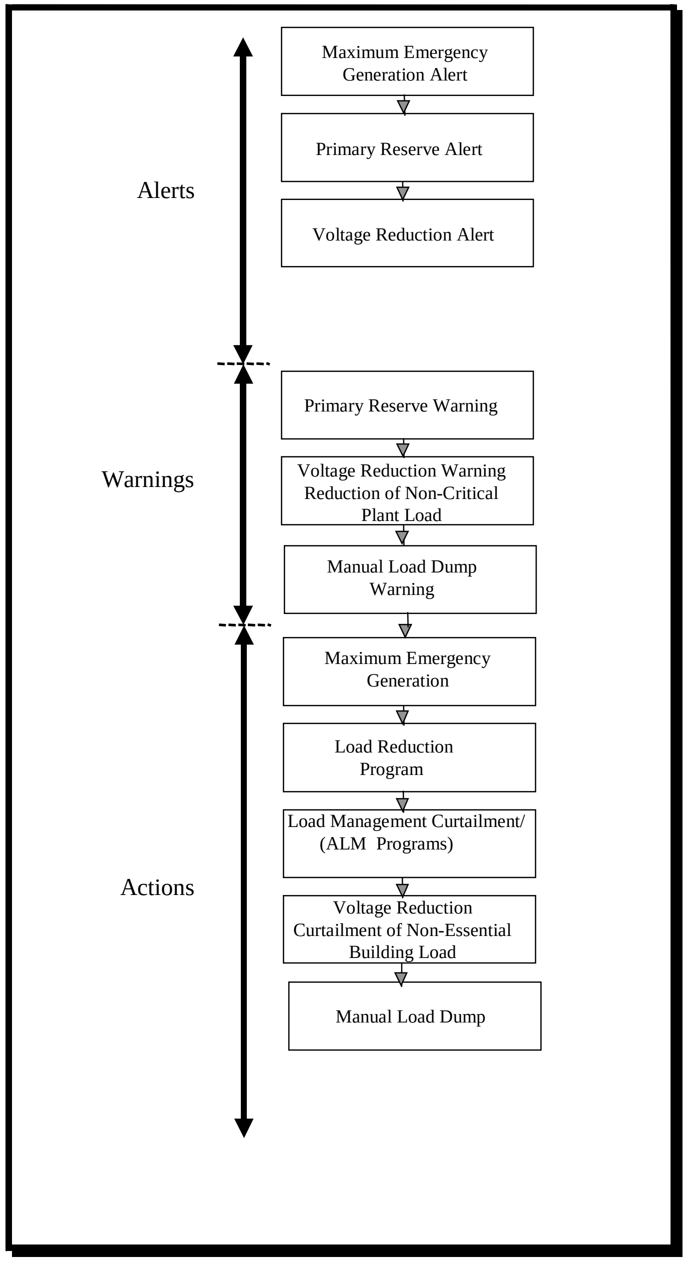
Case Study - Incentive-Based Demand Response

1.0 Demand Response Service:

Demand Resource (DR) / Interruptible Load For Reliability (ILR)

Sponsoring Entity: PJM Interconnection

1.1 Description of Service	Collectively, DR and ILR are referred to as Load Management (LM). Load Management has the ability to reduce metered load, either manually by the customer, after a request from the resource provider which holds the Load Management rights or its agent, or automatically in response to a communication signal from the resource provider which holds the Load Management rights or its agent (for Direct Load Control). DR is load management that actively participates in the RPM auction by bidding into the Base Residual Auction three years in advance of the delivery year. If cleared in the auction, DR receives the auction clearing price. ILR is load management that certifies shortly before the start of the delivery year. ILR receives a price that is a blend of the auction clearing prices less any congestion charges. Load Management receives payments as part of PJM's capacity market, the Reliability Pricing Model (RPM). Payments accrue daily during the delivery year and are credited to the Curtailment Service Provider (CSP) in their monthly PJM bill. Load Management credits are treated as additional capacity in the CSP's resource portfolio.

	
1.2 Type of Resource(s) Provided	**Load Management** that qualifies as DR or ILR must be one of the following types: ▪ **Direct Load Control (DLC)**: Load management that is initiated directly by the resource provider's market operations center or its agent, employing a communication signal to cycle equipment (typically water heaters or central air conditioners).

	▪ **Firm Service Level (FSL)**: Load management achieved by a customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the resource provider's market operations center or its agent. ▪ **Guaranteed Load Drop (GLD)**: Load management achieved by a customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the resource provider's market operations center or its agent. Typically, the load reduction is achieved through running customer-owned backup generators, or by shutting down process equipment. For each type of LM above, there can be two notification periods: ▪ **Step 1 (Short Lead Time)**: LM which must be fully implemented in one hour or less from the time the PJM dispatcher notifies the market operations center of a curtailment event. ▪ **Step 2 (Long Lead Time)**: LM which requires more than one hour but no more than two hours, from the time the PJM dispatcher notifies the market operations center of a curtailment event, to be fully implemented. All PJM Load Management resources are susceptible to being deployed during system emergencies. In the emergency procedures hierarchy, Load Management follows Maximum Emergency Generation and precedes Voltage Reduction.
1.3 Qualification Criteria	A Curtailment Service Provider who wishes to utilize LM must the following capability: • A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process. • Supplemental Status Reports, detailing LM available, as requested by PJM. • Entry of customer-specific LM certification information, for planning and verification purposes, into the PJM eLoadResponse® system. • Customer-specific compliance and verification information for each PJM-initiated LM event, as well as aggregated LM resource provider load drop data for resource provider-initiated events. • Hourly load drop estimates for all LM events. ***LM Qualification*** The entity requesting LM must verify that each customer's load management meets the following criteria: • Availability for up to the ten (10) PJM-initiated interruptions at any time during the planning period.

	• Interruptions of up to six (6) consecutive hours duration between 12:00 PM (Noon) to 8:00 PM (Eastern Prevailing Time) for the months of May through September and 2:00 PM to 10:00 PM for the months of October through April on weekdays, other than PJM holidays. • Load management must be able to be implemented within two hours of notification to the LM resource provider of a PJM-initiated load management event. • Initiation of load interruptions upon request of PJM must be within the authority of the LM resource provider dispatcher without any additional approvals being required. DLC programs are certified based on load research and customer subscription data.
1.4 Performance Measures & Testing	**Metering Requirements –** For FSL and GLD customers, must be able to support hourly integrated load readings. **Testing Requirements –** Load Management customers are explicitly exempted from testing requirements. **Performance Measurements –** Each PJM-initiated Load Management event results in a review of LM Provider performance. The review establishes potential under/over compliance values for the LM Provider. Compliance is event based (compliance is verified only if an event occurs between June and September). Compliance for Direct Load Control programs will consider only the transmission of the control signal. LM Providers are required to report the time period (during the LM event) that the control signal was actually sent. Compliance is checked on an individual customer basis for FSL, by comparing actual load during the event to the firm service level. LM Providers must submit actual customer load levels (for the event period) for the compliance report. Compliance is checked on an individual customer basis for GLD, by comparing actual load dropped during the event to the nominated amount of load drop. LM Providers must submit actual loads and comparison loads for the compliance hours. Comparison loads must be developed from the guidelines included in Attachment A, and note which method was employed. Compliance is averaged over the full hours of an LM event, for each customer or DLC program.

For Interruptible Load for Reliability (ILR), compliance will be totaled over all FSL and GLD customers and DLC programs, by zone, to determine net ILR Provider compliance position(s) for the event.

For Demand Resource (DR), compliance will be totaled over all FSL and GLD customers and DLC programs, by the RPM auction into which it was entered, to determine net DR Provider compliance position(s) for the event.

For any LM event where the DR/ILR Provider's load management provided is less than the DR/ILR Provider's nominated value, a Compliance Deficiency Value will be equal to the DR/ILR deficiency for the event.

Penalties/Rewards

Penalties and rewards are assessed for PJM-initiated events on an event basis, following a compliance review.

A Load Management Compliance Penalty Charge is assessed to those Providers that under-complied during an event. The Load Management Compliance Penalty Charge is equal to the net zonal under-compliance MW times the Load Management Zonal Compliance Penalty Rate. The Load Management Zonal Compliance Penalty Rate per MW-event is one-fifth of the annual revenue rate ($/MW-year) applicable to the Demand Resource or ILR resource.

The total Load Management Zonal Compliance Deficiency Penalties assessed to the Provider in a year is capped at the annual revenue rate the Demand Resource or ILR resource would receive.

The Load Management Compliance Penalty Charges collected from LM Providers are allocated the third billing month after the event occurs (e.g., June events will be included in the August bill, which is issued in September) on a pro-rata basis to those LM Providers that provided load reductions in excess of the amount obligated. The allocation to each over-performing Provider shall not exceed for each ILR resource or Demand Resource the volume of excess MWs provided by the resource during a single event times 1/5 of the annual revenue rate received by the ILR resource or Demand Resource.

Any Load Management Compliance Penalty Charges not allocated to over-performing Providers are instead allocated to all LSEs in the RTO based on the LSE's average Daily Unforced Capacity Obligation during the month the PJM-initiated Load Management event occurred

ERCOT's LAaRs Program

Case Study - Incentive-Based Demand Response

6.0 Demand Response Service:

Load Acting as a Resource (LaaR)

Sponsoring Entity: ERCOT

6.1 Description of Service	LaaR refers to loads with interruptible or dispatch capabilities that are qualified with ERCOT to provide certain Ancillary Services. LaaR are eligible for capacity payments from ERCOT's day-ahead Ancillary Services markets regardless of whether the resource is actually deployed. The value of a LaaR's consumption reduction is equal to an increase in generation by a generating plant. A load's participation in the ERCOT market must be conducted through a Qualified Scheduling Entity (QSE) under contract with the customer. As of October 2007, 130 LaaR providers are registered and qualified with 1,960 MW of load. Currently LaaRs can provide a maximum of 50% of the total hourly ERCOT Responsive Reserve Service (RRS) obligation. This corresponds to a maximum of 1150 MW of RRS provided from LaaRs under the current 2300 MW total hourly RRS obligation. LaaRs can be deployed in 4 ways: 1. Automatic trip based on Under Frequency Relay settings 2. Verbal dispatch by ERCOT during EECP event (deployed as block) 3. Verbal dispatch by ERCOT during frequency event reportable to NERC (deployed as block) 4. Verbal dispatch by ERCOT to solve a local congestion issue (location-specific) LaaRs have been deployed five times since January 2006: 1. April 17, 2006 Emergency Electric Curtailment Plan (manual) 2. Oct. 3, 2006 frequency event (manual) 3. Dec. 22, 2006 frequency event (UFR & manual)

	4. July 2, 2007 frequency event (manual) 5. Sept. 5, 2007 frequency event (manual)
6.2 Type of Resource(s) Provided	**Interruptible Loads** that qualify as LaaR are eligible to provide the following Ancillary Services: ▪ **Responsive Reserve Service (RRS)**: Requires that an Under Frequency Relay (UFR) be installed that opens the load feeder breaker automatically on detection of an under frequency condition. These loads are also required to interrupt manually within a 10-minute notice by verbal dispatch by ERCOT operators. Loads qualified for RRS are automatically qualified for NSRS, RPRS and BES. ▪ **Non-Spinning Reserve Service (NSRS):** Requires that interruptible loads be manually interrupted (e.g., opening a circuit breaker) with 30 minutes notice ▪ **Up Regulation Service (URS) & Down Regulation Service (DRS):** May be provided only by Controllable Load Resources (CLR), a new type of LaaR capable of controllably reducing or increasing consumption under dispatch control (similar to AGC) and able to immediately respond proportionally to frequency changes (similar to generator governor action). Currently, CLRs must be located at sites that provide net generation to the ERCOT grid. CLRs are also qualified to provide RRS and NSRS. ▪ **Balancing Energy Service Up (BES):** Requires that loads be able to respond through manual or automatic operations to interrupt load within 10 minutes ▪ **Replacement Reserve Service (RPRS):** Loads that were planning to be on-line but not providing any other Ancillary Service. LaaRs that are awarded in the day-ahead RPRS market are required to submit BES bids for the appropriate hours the following (operating) day. LaaRs providing RRS, NSRS, URS, DRS and BES must be equipped with real-time telemetry to the ERCOT Operations Center. All ERCOT Resources are susceptible to being deployed during system emergencies or when no other market solution exists to solve certain system operating problems.
6.3 Qualification Criteria	**Provisional Qualification for RRS & NSRS** Loads may be provisionally qualified for a period of ninety days as a LaaR and may be eligible to participate as Resource. To request provisional qualification for RRS and/or NSRS, the following is required: 1. Resource Registration (complete, or update, Resource Registration form) 2. Asset registration of LaaR (complete “Resource: Loads acting as a Resource Registration” form)

	3. Telemetry is in place and tested through the QSE to ERCOT showing: a. Load MW telemetry on each breaker of LAAR (Each registered LAAR may consist of load on multiple breakers; for multiple loads less than 10 MW, then calculated MW is allowed) b. Breaker status (Physical breaker status for load greater than 10MW; for breaker load less than 10 MW, then calculated breaker status is allowed) c. Response MW telemetry (non-zero when supplying service) d. For RRS, the status of the high set under frequency relay. e. Verify LaaR response in QSE's schedule control error (SCE) 4. Affidavit for provisional qualification of Loads is executed and provided to the ERCOT Demand Side Resource Coordinator. **Registration Requirements for RRS, NSRS & BES** Prior to being tested, each Load requesting to be qualified to provide LaaR shall have in place: 1. Resource Registration (complete, or update, Resource Registration form) 2. Asset registration of LaaR (complete "Resource: Loads acting as a Resource Registration" form) 3. Provide simplified one-line diagram of LaaR facilities that include the control switches, operating devices, telemetry points, etc. 4. For RRS, high set under-frequency relay (UFR) set point documentation of the relay used to shed load at low frequency, the relay set point and typical loads to be shed is provided to the ERCOT customer representative and local TDSP. This documentation shall include the relay frequency setting as well as the operating time. (Loads shall have their UFR tested to operate no lower than 59.7 Hz with an operating time of 20 cycles or less.) 5. Provide simplified one-line diagram of LaaR facilities that include the UFR, control switches, operating devices, telemetry points, etc and label as Attachment A to the registration form. 6. Telemetry is in place and tested through the QSE to ERCOT (see "Performance Measures") 7. Affidavit for Actual or Simulated Load Shedding Test executed and provided to the ERCOT Demand Side Resource Coordinator 8. *Test date and deployment window is scheduled with ERCOT Demand Side Resource Coordinator and with the local TDSP representative. The TDSP is required only for simulated test. To schedule, complete the top portion of the RESULTS of RESPONSIVE RESERVE QUALIFICATION TESTING form and submit to the ERCOT Demand Side Resource Coordinator.* **Registration Requirements for CLR** Due to the limitations within ERCOT's existing zonal market system a

	CLR qualified to provide the various Ancillary Services (A/S) can only participate under the following conditions: 1. Power flow at point of settlement meter must be net generation while providing services as a CLR. 2. A/S bids submitted on behalf of the CLR must be submitted as a “GEN” resource type. 3. Able to respond proportionately to frequency changes (similar to generator governor action). 4. Capable of reducing or increasing consumption in response to dispatch instruction (similar to AGC). 5. Due to net generation requirement, the Resource/QSE agrees to waive its right to any resource-specific premium payments that would result from a resource specific instruction (OOME) to the CLR.
6.4 Performance Measures & Testing	**Metering Requirements -** Must be either Interval Data Recorder (IDR) or ERCOT Polled Settlement (EPS) **Telemetry Requirements:** 1. Load MW telemetry on each breaker of LaaR: Each registered LaaR may consist of load on multiple breakers; for multiple loads less than 10 MW, calculated MW is allowed. 2. For CLR, Load MW telemetry on each CLR point (for multiple loads less than 10 MW, an aggregated calculated MW value is allowed). 3. Breaker status: Physical breaker status for load greater than 10MW; for breaker load less than 10 MW, calculated breaker status is allowed. 4. Response MW telemetry (non-zero when supplying service) 5. Status of the high set UFR 6. Verify LaaR response in QSE’s schedule control error (SCE) ***Interruptible Load Qualification Testing Procedure*** QSEs wanting to qualify their Interruptible Load for the first time as LaaR should propose a test date for tripping such loads or simulating such a trip with ERCOT. Each test shall be scheduled through the ERCOT Demand Side Resource Coordinator. Testing may be accomplished by either actual load shedding, or simulation, at the requestor’s option. If simulation is requested, the simulation must be witnessed and coordinated by a representative of the local TDSP. 1. Test procedure for actual load shedding follows: On the date of the test the ERCOT Testing Operator shall call the QSE on a recorded phone line at a time left to ERCOT’s discretion but within the agreed upon test window and order the interruptible load used as RRS to be removed from service.

	At the direction of ERCOT, the QSE Operator shall initiate shedding of the load to be tested, recording the load prior to shedding, the name of the load shed (in the case of feeder loads the name of the substation and feeder line will suffice), the time of the shedding action, and any limiting factors. During this test ERCOT will remain in telephone contact with the QSE shedding load. The ERCOT Testing Operator will announce immediately when he/she observes the load shed. The load shedding entity may immediately restore the shed load. 2. Test procedure for simulated load shedding follows: Simulated load interruption will be accomplished with the local TDSP representative present as a witness. Scheduling testing with the local TDSP and fees associated with TDSP support will be the responsibility of the entity requesting qualification. With the TDSP representative present as a witness the following tests shall be performed. Prior to beginning any testing the TDSP and QSE representatives will each communicate their readiness with the ERCOT Operations Supervisor. 3. Primary configuration to Simulate Load Shed To simulate load shedding, the under-frequency relay is to be disconnected from the breaker and its outputs connected to a load simulating the breaker pickup coil impedance. The affidavit for actual or simulated load shed test is to be executed and provided to ERCOT acknowledging the test method is consistent with the method to be used during an actual manual deployment of the LaaR. 4. Alternate configuration to Simulate Load Shed If the primary configuration does not accurately represent the configuration to be used during a manual deployment of the LaaR, an alternate configuration may be proposed by the requesting entity. Only proposals, which include a method where a TDSP witness can observe a simulated pickup of the breaker coil impedance, will be considered for the test. The affidavit for actual or simulated load shed test is to be executed and provided to ERCOT acknowledging the test method is consistent with the method to be used during an actual manual deployment of the LaaR. To simulate ERCOT deployment of RRS, the TDSP representative will call ERCOT and ask ERCOT to issue a manual deployment to the load being tested. ERCOT will issue a verbal manual deployment of RRS to the QSE specifying the specific LaaR resource to be shed. ERCOT will then

communicate with the TDSP representative on site and confirm that a load disconnect instruction is received and deployed within 10 minutes of the deployment instruction to the QSE. ERCOT will confirm with the TDSP representative the MW amount of load shown on the point being tested.

Controllable Load Qualification Testing Procedure for URS

The Up Regulation Service qualification test is conducted during a continuous sixty (60) minute period agreed on in advance by the Resource/QSE entity and ERCOT. For the sixty (60) minute duration of the test, when market and reliability conditions allow, the ERCOT Demand Side Resource Test Coordinator shall send a random sequence of raise, hold, and lower control signals to the QSE, To facilitate accurate measurements, each signal (raise, lower, or hold) shall remain unchanged for at least two (2) minutes. Also during this same period the ERCOT Demand Side Resource Test Coordinator will instruct the QSE to have only the CLR(s) assets being tested participating in regulation (i.e.; no non-CLR assets participating in regulation). The control signals shall not request CLR performance beyond the stated high limit, low limit, and ramp rate limit agreed on prior to the test. During the test, one ten (10) minute period will test the CLR's ability to achieve the entire amount of Regulation Up requested for qualification during the period.

The CLRs average response to instruction for each clock minute will be measured and recorded. The regulation test shall be conducted when all other schedules are held constant so that any response is the result of the regulation requirement. The correlation coefficient between the expected average response from one minute to the next [limited to no more than the initial value + (request ´ 1/2 ´ stated ramp rate)], and the actual measured response during those minutes shall be statistically significant to two (2) positive standard deviations in order to pass the test.

Controllable Load Qualification Testing Procedure for DRS

The Down Regulation Service qualification test is conducted during a continuous sixty (60) minute period agreed on in advance by the Resource/QSE and ERCOT. For the sixty (60) minute duration of the test, when market and reliability conditions allow, the ERCOT Demand Side Resource Test Coordinator shall send a random sequence of lower, hold, and raise control signals to the QSE, To facilitate accurate measurements, each signal (lower, hold, and raise) shall remain unchanged for at least two (2) minutes. Also during this same period the ERCOT Demand Side Resource Test Coordinator will instruct the QSE to have only the CLR(s) assets being tested participating in regulation (i.e.; no non-CLR assets participating in regulation). The control signals shall not request CLR performance beyond the stated high limit, low limit, and ramp rate limit agreed on prior to the test. During the test, one ten (10) minute period will test the CLR's ability to achieve the entire amount of Regulation Down requested for qualification during the period.

The CLRs average response to instruction for each clock minute will be measured and recorded. The regulation test shall be conducted when all other schedules are held constant so that any response is the result of the regulation requirement. The correlation coefficient between the expected average response from one minute to the next [limited to no more than the initial value + (request ´ 1/2 ´ stated ramp rate)], and the actual measured response during those minutes shall be statistically significant to two (2) positive standard deviations in order to pass the test.

Controllable Load Qualification Testing Procedure for RRS

The Responsive Reserve Service qualification test is performed during a continuous eight (8) hour window agreed on by the Resource/QSE and ERCOT. At any time during the window, selected by ERCOT when market and reliability conditions allow, and not previously disclosed to the Resource/QSE, ERCOT shall send a signal to the QSE requesting it to provide an amount of RRS. Also during this same period the ERCOT Demand Side Resource Test Coordinator will instruct the QSE to have only the CLR(s) assets being tested participating in RRS (i.e.; no other resources automatically (AGC) dispatched participating in RRS). The QSE shall acknowledge the start of the test.

For the thirty (30) minute duration of the test, the QSE output shall be measured as clock-minute average outputs for: (i) the clock-minute prior to the instructions being received from ERCOT; (ii) the clock-minute following receipt of instructions from ERCOT and continuing for ten (10) minutes; and (iii) for each of the subsequent nineteen (19) clock-minutes. All measurements shall confirm the additional delivery of energy due to the deployment of Responsive Reserve Service in an amount equal to at least ninety-five percent (95%) and no more than one hundred five percent (105%) of the amount requested by ERCOT. Satisfactory performance shall be deemed acceptable if ninety percent (90%) of each clock-minute measurement ten (10) minutes after notice through the balance of the test period is equal to at least ninety-five percent (95%) and no more than one hundred five percent (105%) of the amount expected.

Controllable Load Qualification Testing Procedure for NSRS

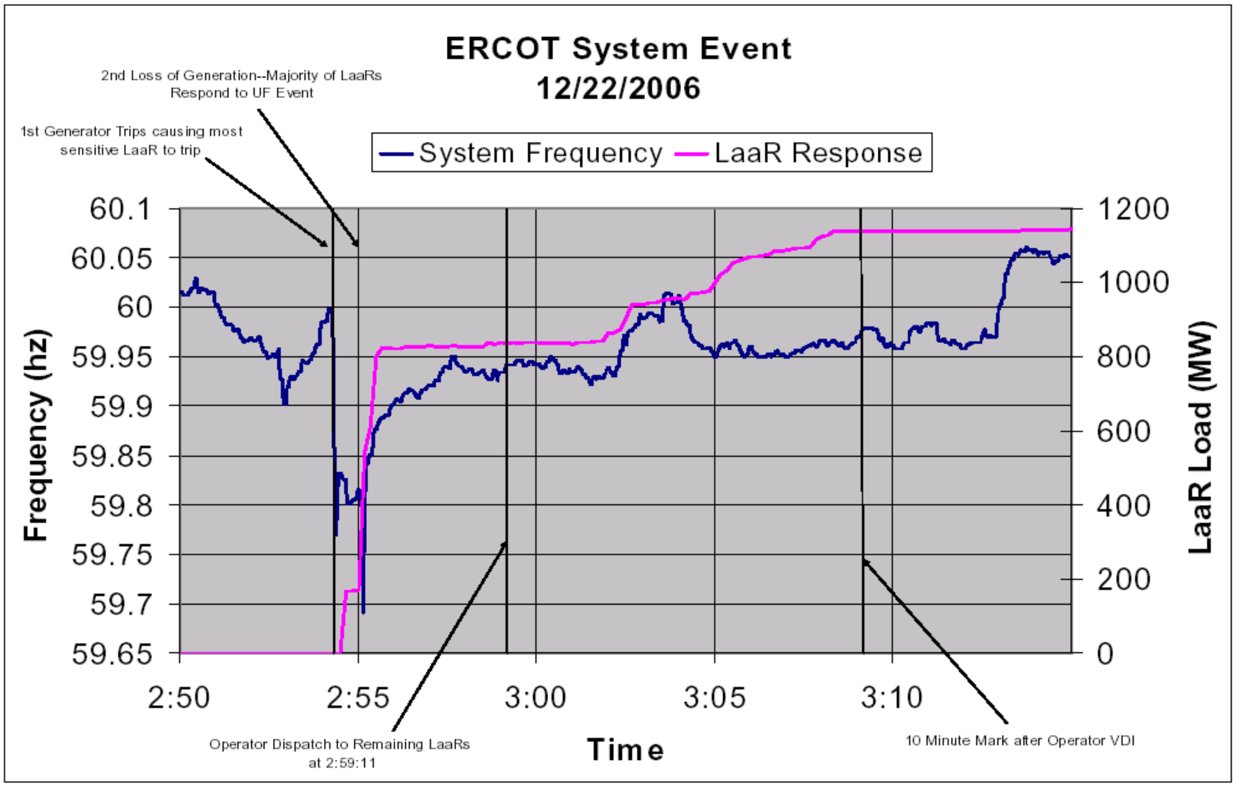
At any time during the window, selected by ERCOT when market and reliability conditions allow and not previously disclosed to the QSE, ERCOT shall notify the QSE using ERCOT's Messaging System requesting it to provide an amount of Non-Spinning Reserve the QSE wishes to be qualified to. Also during this same period the ERCOT Demand Side Resource Test Coordinator will instruct the QSE to have only the CLR(s) assets being tested participating in NSRS (i.e.; no non-CLR assets participating in NSRS). The QSE shall

	acknowledge the start of the test. For the sixty (60) minute duration of the test, the QSE output shall be measured as clock-minute average outputs for: (i) the clock-minute prior to the instructions being received from ERCOT; (ii) the clock-minute following receipt of instructions from ERCOT and continuing for thirty (30) minutes; and (iii) for each of the subsequent twenty-nine (29) clock minutes. All measurements shall confirm the additional delivery of energy due to the deployment of Non-Spinning Reserve Service in an amount equal to at least ninety-five percent (95%) and no more than one hundred five percent (105%) of the amount requested by ERCOT.
6.5 Application to Emergency Electric Curtailment Plan (EECP)	**EECP Steps** Step 1. Maintain ERCOT Physical Responsive Capability (PRC) on units plus RRS MW provided from LaaR Equal to 2300 MW. Step 2. Maintain ERCOT Physical Responsive Capability (PRC) on units plus RRS MW Provided from LaaR Equal to 1750 MW. Step 3. Maintain system frequency at 60 Hz: Following deployment of the measures associated with Steps 1 and 2, ERCOT will deploy all available Emergency Interruptible Load Service (EILS)[13] Resources as a single block via a single Verbal Dispatch Instruction to all QSEs providing EILS. Step 4. Maintain system frequency at 59.8 Hz or greater In addition to measures associated with Steps 1, 2 and 3, ERCOT will direct all TDSPs and their agents to shed firm Load, in one hundred (100) megawatt (MW) blocks, distributed as agreed and documented in the ERCOT Operation procedures in order to maintain a steady state system frequency of 59.8 Hertz (Hz). ERCOT may take this action prior to the expiration of the ten (10) minute EILS Resource deployment period if ERCOT, in its sole discretion, believes that shedding firm Load is necessary to maintain the stability of the ERCOT System. If, due to ERCOT System conditions, EILS Resources are not deployed prior to this action, ERCOT shall deploy EILS Resources as soon as possible following this action. In addition to measures associated with Steps 1 and 2, TDSPs will keep in mind the need to protect the safety and health of the community and the essential human needs of the citizens. Whenever possible, TDSPs shall not manually drop Load connected to under-frequency relays during the implementation of the Emergency Electric Curtailment Plan.
6.6 Assessment of Resource	1125 MW LaaR RRS is reported in “Availability of Resources for

13 EILS is a special emergency service required by Public Utility Commission of Texas Substantive Rule §25.507, adopted in April 2007. To date the program has not been operated, as the minimum 500 MW participation requirement has not been met.

Adequacy	Medium-term PASA" (Projected Assessment of System Adequacy). This represents the average hourly LaaR component of ERCOT Responsive Reserves during the preceding calendar year (2006).

6.7 Example of Resource Response



Source: ERCOT Operations Report on the EECP Event of December 22, 2006	
6.8 Definitions	**Ancillary Services** are those services, described in Section 6, necessary to support the transmission of energy from Resources to Loads while maintaining reliable operation of transmission provider's transmission systems in accordance with Good Utility Practice. **Balancing Energy** represents the change in zonal energy output or demand determined by ERCOT to be needed to ensure secure operation of ERCOT Transmission Grid, and supplied by the ERCOT through deployment of bid Resources to meet Load variations not covered by Regulation Service. **Balancing Up–Load (BUL)** is a market participant that can interrupt load in response to a request from ERCOT to provide Balancing Energy Services, and is compensated through the market similar to a generator providing Balancing Energy Services. **Dispatch Instruction(s)** are specific command(s) issued by ERCOT to QSEs or TDSPs during the course of operating the ERCOT System. **Distribution Service Provider (DSP)** is an Entity that owns and maintains a Distribution System for the delivery of energy from the ERCOT Transmission Grid to the Customer. **Emergency Electric Curtailment Plan (EECP)** is a plan which provides an orderly, predetermined procedure for maximizing use of available Resources and, only if necessary, curtailing demand during electric system emergencies while providing for the maximum possible continuity of service and maintaining the integrity of the ERCOT System. **Emergency Interruptible Load Service (EILS)** is a special emergency service used during an EECP Step 3 or 4 to reduce Load and assist in maintaining or restoring ERCOT System frequency. **ERCOT Polled Settlement (EPS) Meter** is any meter polled by ERCOT as defined in Section 10 for use in the financial settlement of the Market. **Interval Data Recorder (IDR)** is a metering Device that is capable of recording Load usage in each Settlement Interval in accordance with

	ERCOT Protocols Section 9, Settlement and Section 10, Metering. **Load Acting as a Resource (LaaR)** is a load that can interrupt in response to a request from ERCOT under various Ancillary Services programs. LaaRs are eligible for capacity payments for making their loads available for curtailment. If they are deployed, they also receive energy payments for actually delivering the load reduction. **Non-Opt In Entity (NOIE)** is a municipally owned utility or electric cooperative that has not chosen to offer customer choice. **Non-Spinning Reserve Service (NSRS)** is a service that is provided through utilization of the portion of off-line generation capacity capable of being synchronized and ramped to a specified output level within thirty (30) minutes (or Load that is capable of being interrupted within thirty (30) minutes) and that is capable of running (or being interrupted) at a specified output level for at least one (1) hour. Non-Spinning Reserve Service (NSRS) may also be provided from unloaded on-line capacity that meets the above response requirements and that is not participating in any other activity, including ERCOT markets, self-generation and other energy transactions. **Out of Merit Order (OOM)** is the selection of Resources for Ancillary Services that would otherwise not be selected to operate because of their place (or absence) in the bidding process for that service. **Power Generation Company (PGC)** generates electricity that is intended for the wholesale market. A PGC cannot own a transmission or distribution facility other than that essential for interconnection. **Qualified Scheduling Entity (QSE)** is the entity that submits daily balanced schedules to ERCOT. The QSE also manages Ancillary Services bids, including those from the LaaR program. QSEs are responsible for all financial settlement activities with ERCOT, and must obtain certification demonstrating that they are financially responsible to ERCOT for all bills and payments. A QSE may be a REP, a PGC, a NOIE, a PM, or a combination of several entities. A QSE may represent multiple REPs, and a REP may contract with multiple QSEs to schedule its services. **Regulation Service (RGS)** is a service that is used to control the power output of Resources in response to a change in system frequency so as to maintain the target system frequency within predetermined limits. **Replacement Reserve Service (RPRS)** is a service that is procured from Generation Resource units planned to be off-line and Load acting as a Resource that are available for interruption during the period of requirement. **Resource** is any facilities capable of providing electrical energy or Load capable of reducing or increasing the need for electrical energy or providing Ancillary Services to the ERCOT System, as described in Section 6, Ancillary Services. This includes Generation Resources, Loads Acting as a Resource (LaaR) and Emergency Interruptible Load

	Service (EILS) Resources. **Resource Entity** is a Market Participant that owns or controls a Resource. **Resource Plan** is provided by a QSE to ERCOT indicating the forecast state of Generation Resources or individual Loads each acting as a Resource (LaaRs), including information on availability, limits and forecast generation or Load of each Resource. **Responsive Reserve Service (RRS)** consists of the daily operating reserves that are intended to help restore the frequency of the interconnected transmission system within the first few minutes of an event that causes a significant deviation from the standard frequency. **Retail Electric Provider (REP)** is a category of market participant registered with the PUCT that sells electric energy to retail customers. A REP may not own or operate generation assets. **Schedule Control Error (SCE)** is the difference in the QSE's actual Resource output and its base power schedule plus instructed Ancillary Services. **Scheduling Process** is the process through which schedules for energy and Ancillary Services are submitted by QSEs to ERCOT as further described in ERCOT Protocols Section 4, Scheduling. **Transmission/Distribution Service Provider (TDSP)** is that portion of the former vertically integrated utility that owns and maintains equipment or facilities to transmit and distribute electricity over a certified service area. Rates that the TDSPs must charge for transmission and distribution services are set by the Public Utility Commission of Texas.
6.9 Governing Documents	All documents from the ERCOT website at http://www.ercot.com **ERCOT Protocols:** Section 2: Definitions and Acronyms Section 6: Ancillary Services, August 1, 2007 Section 16: Registration and Qualification of Market Participants, August 1, 2007 Section 17: Market Data Collection and Use, July 1, 2001 Section 22: Attachment C, Standard Form Qualified Scheduling Entity Agreement Section 22: Attachment E, Standard Form Resource Entity Agreement **ERCOT Operating Guides:** Section 2: System Operations, July 1, 2007 Section 3: Operational Interfaces, July 1, 2007 Section 4: Emergency Operations, July 1, 2007

	Section 8: Operational Metering and Communications, July 1, 2007 **Other Documents:** LaaR Responsive Reserve Qualification – ERCOT Process for Qualification Testing of High Set Interruptible Load In Accordance With ERCOT Protocols and Guides LaaR Balancing Energy Service Qualification – ERCOT Process For Qualification Testing of Loads Providing Balancing Energy Services In Accordance with ERCOT Protocols and Guides LaaR Non-Spinning Reserve Qualification – ERCOT Process for Qualification Testing of Loads Providing Non-Spinning Reserve Service in Accordance with ERCOT Protocols and Guides Load Participation in the ERCOT Market, Financial Opportunities for Reducing Electricity Load, An Introduction to ERCOT's Load Reduction Programs and the ERCOT Protocols, Revised May 2006 2007-2008 ERCOT Methodologies for Determining Ancillary Service Requirements, July 2, 2007

NYISO
Demand Bidding Buyback

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Case Study – Demand Bidding Buyback

1.0 Name of Demand Response Service & Sponsoring Entity
1.1 Description of Service
1.2 Types of Resources Provided
1.3 Qualification Criteria
1.4 Performance Measures & Testing
1.5 Application to EECP (NERC EOP-1)
1.6 Assessment of System Adequacy
1.7 Example of Resource Response
1.8 Definitions
1.9 Governing Documents
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1.0 Demand Response Service:
Day-Ahead Demand Response Program (DADRP)
Sponsoring Entity: NYISO
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1.1 Description of Service
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The DADRP provides retail customers with an opportunity to bid their load curtailment capability into the day-ahead spot market as energy resources. Customers submit bids by 5:00 a.m. specifying the hours and amount of load curtailment they are offering for the next day, and the price at which they are willing to curtail. The bid floor price is $75/MWh and a single bid is limited to a strip of no more than eight hours.

Bids are structured like those of generation resources. DADRP program participants may specify minimum and maximum run times and effectively submit a block of hours on an all-or-nothing basis. They are eligible for production cost guarantee payments to make up for any difference between the market price received and their block bid price across the day.

Load scheduled in the Day-Ahead Market (DAM) is obligated to curtail the next day. Failure to curtail results in the imposition of a penalty for each such hour defined by the MW curtailment shortfall times the greater of the corresponding day-ahead or real-time market price.
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1.2 Type of Resource(s) Provided
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Individual or Aggregated demand-side resources with a minimum of 1 MW of load reduction capability are eligible to participate. Load reduction through on-site generation is not permitted in this program.

Small Customer Aggregation – Aggregations must be at
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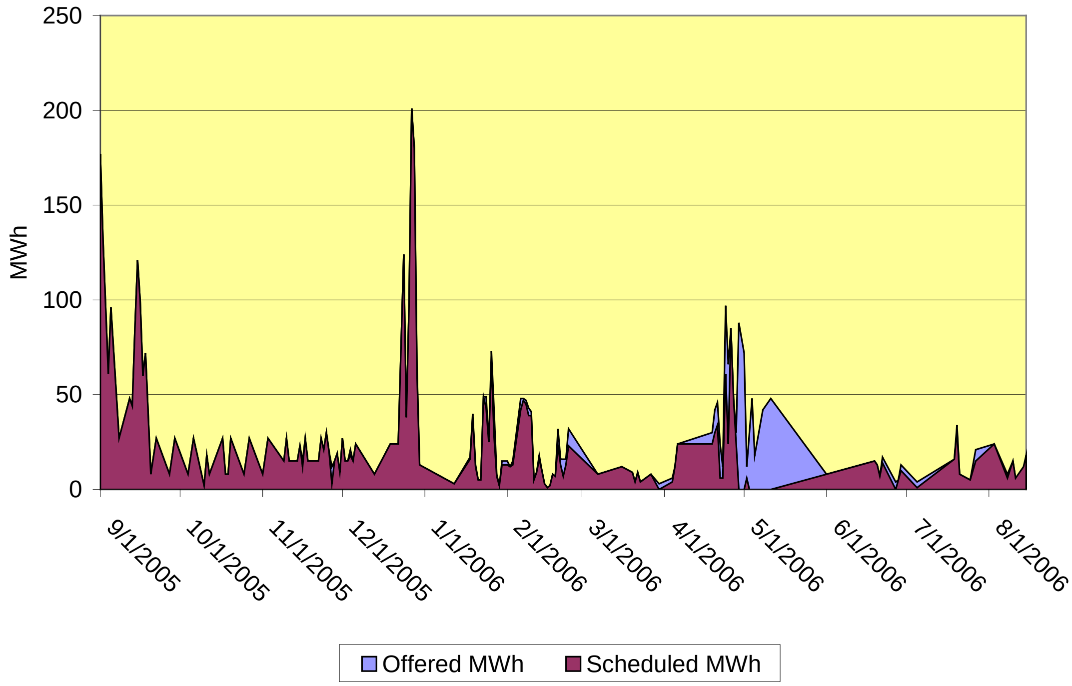
	least 1.0 MW for DADRP. The NYISO will establish an up-front means of certifying that the aggregation has an expectation of meeting this requirement. This will be established as part of the approval of the verification methodology; the sampling plan or other measurement methodology will assign an initial (a priori deemed) estimate of the response per site in order to drive the sample size. The aggregation must be comprised of two or more sampling methods, provided that such a super aggregations was allowed by the NYISO. Aggregators must accept full responsibility for payments to and penalties levied against the members of the aggregation. The NYISO will require that each member of the aggregation execute an agreement to participate indicating that it accepts the provisions of the ISO program and authorizes the Demand Reduction Provider (DRP) to act as its broker for the purposes of participation.
1.3 Qualification Criteria	Demand Reduction Bids may be submitted by a DRP on behalf of a participating demand-side resource. Any demand-side resource or aggregation capable of the minimum load reduction of 1 MW is eligible to participate.
1.4 Performance Measures & Testing	**Metering Requirements –** An hourly interval billing meter is required for each participating load. Demand-side resources must have an integrated hourly metering device, installed to capture the facility's net load, and certified by a Meter Service Provider (MSP). DADRP participants must contract with a Meter Data Service Provider (MDSP) for collection and reporting of DADRP data to the NYISO. **Testing Requirements –** There are no testing requirements for DADRP resources. **Performance Measurements –** A Demand Side Resource's Customer Baseline Load (CBL) will provide a reference to verify its compliance with a scheduled curtailment. The CBL is based upon the five highest energy consumption levels in comparable time periods over the past ten days, beginning two days prior to the day for which the load reduction is bid. The amount of actual real-time curtailment determined will be equal to the CBL less the real-time consumption during the

	scheduled curtailment. ***Payments*** A DRP with a Demand Side Resource that curtails load (as scheduled Day-Ahead by the NYISO) will be paid by the NYISO the higher of the Demand Reduction Bid or Day-Ahead LBMP. If needed, a supplemental payment will be made to allow full recovery of the Curtailment Initiation Cost. ***Penalties*** If a DRP has a Demand Side Resource scheduled for a curtailment and fails to curtail, the DRP will be charged the higher of Day-Ahead or Real-Time LBMP for non-curtailed load.

1.5 Application to Emergency Procedures)	DADRP is an economic demand response program and scheduled resources are not included in emergency procedures unless the resources are also registered in one of NYISO's reliability programs.
1.6 Assessment of Resource Adequacy	The Day-Ahead Demand Response Program has 389 MW of registered resources. In 2006, 1,300 load reduction offers were made by DADRP resources and 1,210 load reduction offers were scheduled, resulting in 3,479 MWh of reduction. Scheduled MWh increased by approximately 75% over the previous year.
1.7 Example of Resource Response	



DADRP MWh 2005 - 2006, Bid vs. Scheduled

1.8 Definitions	**Bid Production Cost -** Total cost of the Generators required to meet Load and reliability Constraints based upon bids corresponding to the usual measures of Generator production cost (e.g., running cost and Minimum Generation and Start-Up Bid). **Curtailment Initiation Cost -** The fixed payment, separate from a variable Demand Reduction Bid, required by a qualified Demand Reduction Provider in order to cover the cost of reducing demand. **Customer Baseline Load (CBL) -** Average hourly energy consumption used to determine the level of load curtailment provided. **Demand Reduction Provider (DRP) –** An entity, qualified pursuant to ISO procedures that bids Demand Side Resources of at least 1 MW. **Demand Side Resource** – A Resource located in the NYCA that is capable of reducing demand in a responsive, measurable and verifiable manner within time limits, and that is qualified to participate in competitive Energy and, to the extent that the ISO's software can support its participation, certain Operating Reserves markets pursuant to this ISO Services Tariff and the ISO Procedures. **Locational Based Marginal Price (LBMP) –** The price

	of energy bought or sold in the LBMP markets at a specific location or zone. **Meter Service Provider (MSP) –** An entity that provides meter services, consisting of the installation, maintenance, testing and removal of meters and related equipment. **Meter Data Service Provider (MDSP) –** An entity providing meter data services, consisting of meter reading, meter data translation and customer association, validation, editing and estimation.
1.9 Governing Documents	All documents from the NYISO website at www.nyiso.com **NYISO Open Access Transmission Tariff** **Market Services Tariff** **Day-Ahead Demand Response Program Manual**

Kansas City Power & Light, TVA, Westar Energy

Traditional Interruptible/Curtailable Service

Case Study – Interruptible Service Rider

2.0 Demand Response Service:

Interruptible Service Rider

Sponsoring Entities: Kansas City Power & Light, TVA, Westar Energy

2.1 Description of Service

A customer agrees to one or more curtailment options in addition to the terms and conditions of the applicable retail tariff. The service is voluntary and usually executed by means of a tariff rider and/or with a bilateral contractual agreement. Customer is given a rate discount or bill credit from firm demand charges as an incentive for agreeing to reduce its load during system contingencies or other events as specified in the tariff rider or contract. Curtailment is usually initiated by verbal dispatch.

The customer is usually allowed to designate only a portion of its total load ("Contracted Demand Reduction") that is exposed to curtailment. Failure to curtail may result in a penalty, although some tariff riders provide for a "buythrough" of the curtailment. Utility usually reserves the right to limit the total capacity (load in MWs) exposed to curtailment.

Comparison of Three Interruptible Service Riders

	KCPL	TVA	Westar
Contract Period	1, 3 or 5 years	5 years	3 years
Reason for Interruption:			
▪ Reliability	Yes	Yes	Yes
▪ Operating Reserves	No	Yes	No
▪ Economic Buy	Yes	Yes	Yes
▪ Economic Sell	Yes	Yes	Yes
Treated Equal to Supply	Yes	Yes	Yes

Curtailment Notice	1 to 4 hours	5 minutes	2 hours
Duration of Interruption	2-8 hrs/day		Varies
Number of Curtailments	25-30/yr	Unlimited	Unlimited
Total Hrs of Curtailment	120 hrs/yr	Unlimited	360 hrs/yr
Customer Buythrough Allowed	Yes	No	Yes
Capacity Payment (kW/month)	$1.33-$3.10	$3.4014	$3.00
Energy Payment (kWh)	$0.80	0	$0.75

2.2 Types of Resources Provided

- Reliability (relieve constraints on generation or T&D system)
- Operating reserves (Spinning or Supplemental)
- Economic buy (marginal cost of supply is greater than the customer's retail rate)
- Economic sell (utility's opportunity to sell energy in the wholesale market is greater than the customer's retail rate)

2.3 Qualification Criteria

TVA Flat Price Interruptible (FPI)
- Industrial customers with interruptible loads above 1 MW at a single delivery point
- Five-year contract with two-year termination notice
- Five-minute interval meter with customer bearing cost of meter or reprogramming; TVA has phone access to meters to verify compliance

Westar Energy
- Customers with at least 500 kW of interruptible load
- Three-year contract with automatic one-year evergreen extension unless either party provides written notice at least 90 days prior to anniversary date

Kansas City Power & Light
- Non-residential customers with at least 200 kW of interruptible load
- Sliding scale of curtailment parameters depending on length of contract with customer:
  - <u>One-Year Contracts</u>: Minimum notification time is 4 hours prior to start of curtailment; Number of curtailments not to exceed 25 per year; Curtailment season runs from May through September.
  - <u>Three-Year Contracts</u>: Minimum notification time is 2 hours prior to start of curtailment; Number of curtailments not to exceed 25 per year; Curtailment season runs from May through September.
  - <u>Five-Year Contracts</u>: Minimum notification time is 1 hour prior to start of curtailment; Number of curtailments not to exceed 30 per year; Curtailment season runs from January through December.
- Each curtailment shall be no less than 2 hours and no more than 8 hours per day, and no more than 3 consecutive days per calendar week.
- The cumulative curtailment hours per customer shall not exceed 120 hours in any calendar year.

2.4 Performance Measures &

KCPL: Reserves the right to request a test curtailment once each year

14 TVA FPI capacity payment is being increased to $4.00/kW demand per month

Testing	and/or within 3 months after a failure to comply with any request for curtailment.
2.5 Application to NERC EOP-1	
2.6 Assessment of Resource Adequacy	
2.7 Example of Resource Response	
2.8 Definitions	**Buythrough** is the ability of a customer served under an interruptible service rider to compensate the utility to defer an interruption. **Contract Period** is the term (usually in years) of the agreement for interruptible service between the customer (load) and the utility. **Contracted Demand Reduction** is the amount of a customer's total demand (kW) that is eligible for curtailment and entitled to a demand charge credit or other financial incentive. **Curtailment Notice** is the time period given to an interruptible customer prior to when the curtailment is to commence. **Demand Reduction** is the credit on a customer's monthly bill for each month of the contract year. The amount of this credit will be based on the contracted demand reduction. **Firm Contract Demand** is the load in kW that a customer intends to exclude from interruption. This amount is usually specified in the agreement for interruptible service with the utility.
2.9 Governing Documents	(1) Kansas City Power & Light Company, "MPower Rider, Schedule MP," Issued June 29, 2006 (2) Tennessee Valley Authority, "Flat Price Interruptible." (3) Westar Energy, Inc., "Interruptible Service Rider," Issued January 2, 2006

Florida Power & Light's Residential Load Management Program

Case Study - Incentive-Based Demand Response

1.0 Demand Response Service:

Residential Load Management

Sponsoring Entity: Florida Power & Light

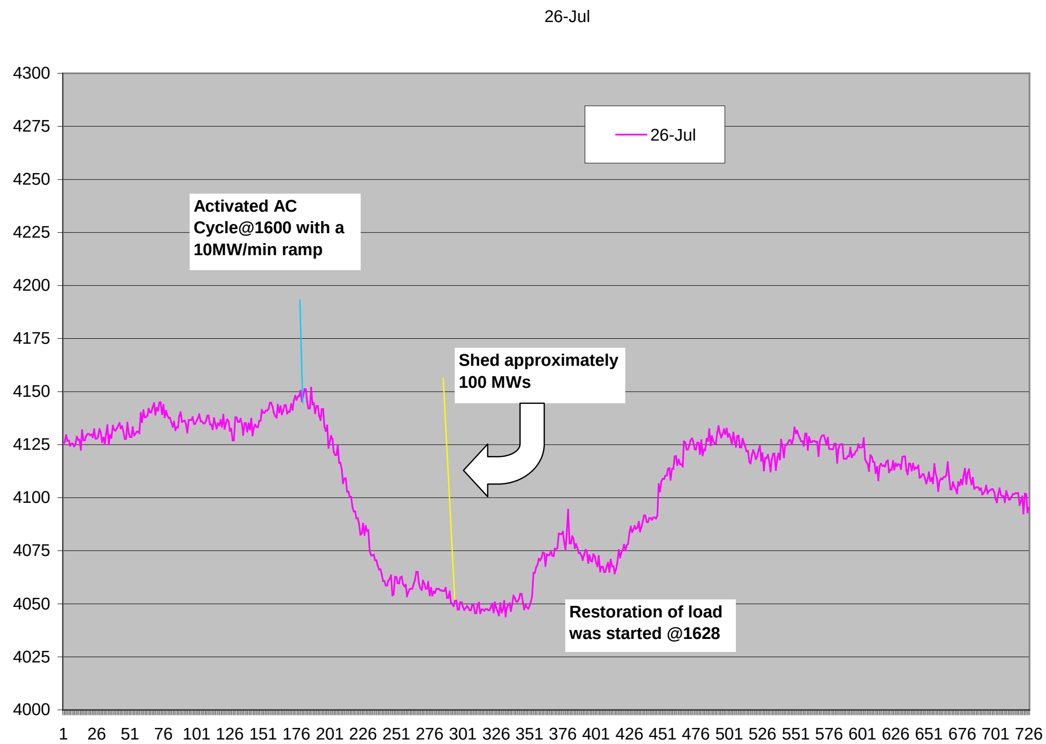
1.1 Description of Service	FPL's residential load management program is marketed as the On Call Program. On Call Program is available to all residential customers who are individually metered (i.e., who do not receive service through commonly owned facilities of condominium, cooperative or homeowners' associations) and who have one or more of the following electrical appliances/equipment: • central electric air conditioners, • central electric space heaters, • conventional electric water heaters, and • swimming pool pumps. A customer may sign up for one or more of these appliances/equipments (with the exception of electric space heating, which is eligible only in combination with one of the other equipment types). Once the customer signs up for the program, the installation is performed by a contractor. Upon installation and inspection of the equipment, the customer receives a monthly credit, which may vary seasonally, on his/her electric bill. The incentives normally are paid as specified in the On Call Program tariff, which is attached. A typical barrier to customer acceptance of utility load control programs is reluctance to surrender control of heating and air conditioning appliances. Consequently, in an upcoming 24-month test period, FPL will be evaluating whether the benefits of the On-Call Program can be expanded through use of a new

	generation of communication and control technologies that put residential customers in charge of decisions that could lower energy costs, while allowing customers to override FPL control of their heating and air conditioning appliances. In place of incentives for control of HVAC equipment, customers receive a programmable thermostat. Actual performance of load management is effected via FPL's Load Management System (LMS). The LMS uses a Master Station (computer) to send a signal through telephone lines to equipment installed at the substations. From the substation, a signal is transmitted through the power lines and received by a transponder (transmitter/receiver) installed at the customers home. The transponder in turn activates its relay to interrupt the appliance circuit for the specified period of control time.
1.2 Type of Resource(s) Provided	The order of activation for DSM options is as follows: ▪ Residential Load Control- "On Call"-Water Heaters / Pool Pumps (SUMMER ONLY). ▪ Residential Load Control- 'On Call"- A/C (SUMMER ONLY) ▪ Residential Load Control- "On Call"- Heaters, (WINTER ONLY) ▪ Commercial / Industrial Load Control and Curtailable rate customers. (This is a different DSM load control option available to large commercial/industrial customers) ▪ Utilize final options, such as "On Call-SCRAM"
1.3 Qualification Criteria	Customer eligibility is based on three primary factors: • whether the customer has the proper eligible loads, • whether their service characteristics (voltage, etc.) are compatible with existing load control equipment, and • whether the customer receives service from a substation which has load control equipment installed.
1.4 Performance Measures & Testing	On Call Program Monitoring & Evaluation FPL's ongoing monitoring & evaluation (M&E) of the On Call Program began with metered field studies in the early 1990s. About every five years, a new random sample of On Call participants is drawn so research meters can be installed on

	their homes to verify or update the demand reduction estimates for the program This enables statistically valid estimates of program impacts to be derived with high precision. FPL's latest plan is to combine residential metered data from the 2005-2008 summer seasons using the sample of 100 research sites now in the field. This will further support the company's commitment to high quality M&E for this valuable demand side management asset. In addition to the metered studies, program participation is tracked for every combination of appliance options such as cycling or shedding of cooling and heating load or shedding of water heater or pool pump load. By closely tracking the number of program participants signed up for each option, the impact of the entire program population is derived. Telephone surveys of On Call program participants are conducted regularly to measure customer knowledge, perceptions, and satisfaction regarding the program. Other information like reasons for participating and the performance of the installation contractors help FPL to better market and manage the On Call program.
1.5 Application to EECP (NERC EOP-1)	A generating capacity emergency is declared when conditions exist such that FPL or any other utility in the state has inadequate generating capacity, or transmission capacity, including purchased power, to supply firm load obligations. Actions to be taken during an emergency will include bringing all generating units to full capability, starting all units that are available, purchasing energy from outside the state, reducing non-essential electric use at utility facilities, using load management, curtailing interruptible customers, reducing voltage within established safe limits, and issuing appeals to consumers for emergency cutbacks of electricity use and voluntary conservation.
1.6 Assessment of System Adequacy	As of September 2007 944.6 MW of load control is available

1.7 Example of Resource Response

Load Control Activation Test July 26, 2007 A/C cycle West area only



1.8 Definitions	
1.9 Governing Documents	See attached tariff

RESIDENTIAL LOAD CONTROL PROGRAM

RATE SCHEDULE: RLP

AVAILABLE:

Available only within the geographic areas served by the Company's Load Management System.

APPLICATION:

To Customers receiving service under Rate Schedule RS-1 who elect to participate in this Residential Load Control Program ("Program") on or after April 1, 2003 and who utilize at least one of the following installed electrical appliances at the Customer's premise:

1. Conventional electric water heater
2. Central electric air conditioning
3. Swimming pool pump (including pool sweeps as appropriate)
4. Central electric space heating*

*Central electric space heating systems alone are ineligible for Program participation. These systems are eligible for Program participation only when one (or more) of the other 3 appliances listed above is (are) signed up for participation.

This Rate Schedule is not applicable for service to commonly-owned facilities of condominium, cooperative, or homeowners' associations.

SERVICE:

The same as specified in Rate Schedule RS-1.

LIMITATION OF SERVICE:

The same as specified in Rate Schedule RS-1. The specified electrical appliances shall be interrupted at the option of the Company by means of load management equipment installed at the Customer's premise.

MONTHLY CREDIT:

Customers receiving service under this Rate Schedule will receive a credit on the monthly bill as follows:

	DEVICE (OPTION)	APPLICABILITY	CREDIT
1.	Conventional electric water heater	Year-round	$ 1.50
2.	Central electric air conditioning (Option C)	April-October	$ 3.00
3.	Central electric air conditioning (Option S)	April-October	$ 9.00
4.	Swimming pool pump	Year-round	$ 3.00
5.	Central electric space heating (Option C)	November-March	$ 2.00
6.	Central electric space heating (Option S)	November-March	$ 4.00

Total monthly credit shall not exceed 40 percent of the Rate Schedule RS-1 "Base Energy Charge" actually incurred for the month (if the Budget Billing Plan is selected, actual energy charges will be utilized in the calculations, not the levelized charges) and no credit will be applied to reduce the Minimum bill specified on Rate Schedule RS-1.

Note: Option C or Option S (listed below) may be selected for either central air conditioning or heating systems. If both appliance types are participating in the Program, the same option must be selected.

(Continued on Sheet No. 8.218)

Issued by: S. E. Romig, Director, Rates and Tariffs
Effective: August 14, 2007

(Continued from Sheet No. 8.217)

INTERRUPTION SCHEDULES FOR ELECTRICAL APPLIANCES

The Customer's participating electrical appliances will be interrupted only during the following periods except as noted below:

April 1 through October 31: 2 p.m. to 10 p.m.

November 1 through March 31: 5 a.m. to 11 a.m.
4 p.m. to 10 p.m.

The interruption schedules available for each appliance are as follows:

1. Conventional electric water heating equipment may be interrupted up to, but not to exceed, 240 minutes per day.

2. Central electric air conditioning equipment may be interrupted under one of the following options selected by the Customer:

   Option C equipment may be interrupted an accumulated total of 15 minutes during any 30 minute period with a cumulative interruption time of up to 180 minutes per day. If normal operation of the Program is not able to provide sufficient demand reduction to divert an emergency situation, central electric air conditioners may be interrupted for 17.5 minutes during any 30 minute period with a cumulative interruption time of up to 210 minutes per day.

   Option S equipment may be interrupted up to, but not to exceed, 180 minutes per day.

3. Swimming pool pump equipment may be interrupted up to, but not to exceed, 240 minutes per day.

4. Central electric space heating equipment may be interrupted under one of the following options selected by the Customer:

   Option C equipment may be interrupted an accumulated total of 15 minutes during any 30 minute period with a cumulative interruption time of up to 180 minutes per day.

   Option S equipment may be interrupted up to, but not to exceed, 180 minutes per day.

The limitations on interruptions of electrical equipment shall not apply during emergencies on the Company's system or to interruptions caused by force majeure or other causes beyond the control of the Company.

TERM OF SERVICE:

During service under this Rate Schedule, a Customer may change interruption options or the selection of electrical appliances connected to the load management equipment or discontinue service under this Rate Schedule by giving the Company 7 days advance notice. If the Customer requests to have one or more appliances removed from participation in the Program, the Customer will be ineligible to participate with such appliance(s) again in the Program for one year (12 months) from the time participation ended.

SPECIAL PROVISIONS

1. The Company shall not be required to install load management equipment if the installation cannot be economically justified for reasons such as: excessive installation costs, oversized/undersized heating or cooling equipment or abnormal utilization of equipment, including vacation or other limited occupancy residences.

2. Billing under this Rate Schedule will commence upon the installation and completion of required inspections of the load management equipment.

3. Multiple units of any particular appliance type must all be connected with load management equipment to qualify for the credit attributable to that appliance type. In such circumstances, only a single credit for that appliance type will be applied. Pool sweeps, when coupled with pool pumps, are included in this category.

(Continued on Sheet No. 8.219)

(Continued from Sheet No. 8.218)

4. Installation of the load management equipment at the Customer's premise is to be the sole responsibility of a licensed, independent contractor. The Customer agrees that the Company shall not be liable for any damages or injuries that may occur as a result of the interruption or restoration of electric service pursuant to the terms of this Rate Schedule.

5. The following types of electric water heaters are ineligible for participation in the Program: solar water heaters, heat recovery units and heat pump water heaters.

6. If the Company determines that the Customer no longer uses one or more of the appliances signed up for Program participation, then the Company has the right to remove the appropriate load management equipment and to discontinue the appropriate credits.

7. The Customer shall give the Company and the licensed, independent contractor reasonable access for installing, maintaining, testing and removing the Company's load management equipment, and for verifying that the equipment effectively controls the Customer's appliances as intended by this Rate Schedule.

8. If the Company determines that the effect of equipment interruptions has been offset by the Customer's use of supplementary or alternative electrical equipment, then service under this Rate Schedule may be discontinued and the Customer billed for all prior Monthly Credits received under this Rate Schedule over a period not to exceed six (6) months.

9. If the Company determines that its load management equipment at the Customer's premise has been rendered ineffective by mechanical, electrical or other devices or actions ("tampering"), then the Company may discontinue the Customer's participation in the Program and bill for all expenses involved in removal of the load management equipment, plus applicable investigative charges. The Company may rebill all prior Monthly Credits received by the Customer from an established tampering date. If such a date cannot be established, then rebilling of the Monthly Credits shall be for the lesser of the number of months receiving service under this Rate Schedule or the previous twelve (12) months.

Appendix III

Historical Ongoing Metrics and Data Requirements

Metric Type / Metric Description	Data Requirements
Population Information	
Annual Expected EE	1) Expected annual MWh saved 2) Expected MW Reduction at time of peak
Number of DR end-users and potential load reduction capability for each demand response resource category	1) Peak MW available 2) Number of end-users
Historical Performance Analysis	
Annual Actual EE	1) Annual MWh saved 2) MW Reduction at time of peak
Number of curtailable events per year and total MW for each demand response resource category	For Each Curtailable Event: 1) Duration of curtailable event (1 hour, 4 hours …) 2) Allowed frequency of curtailable events (1 per day, 3 per week etc.) 3) Notification time required to curtail load (24 hour notice, 1 hour notice) 4) Ramp up (down) time for curtailable load (i.e.10 minutes or less allows it to be considered operating reserves)
Testing requirements: How many times has each demand response option is tested	1) Identify the number of times the signal has been tested. 2) Amount of load MW estimated or verified.
Projections for Seasonal & Long-Term Assessments	
For EE Analysis	1) Expected MW Reduction at time of peak Expected Annual MWh Saved/Net Energy for Load 2) Summer & Winter MW Expected Reduction at time of peak internal demand for a 50/50 forecast

Appendix IV

Glossary

Ancillary: *demand-side resource displaces generation deployed as operating reserves and/or regulation; penalties are assessed for noncompliance*

Capacity: *demand-side resource displaces or augments generation for resource adequacy; penalties are assessed for noncompliance*

Critical Peak Pricing (CPP) with control: *demand-side management that combines direct remote control with a pre-specified high rate for usage designated by the utility to be a critical peak period, triggered by system contingencies or high wholesale market prices faced by the utility.*

Critical Peak Pricing (CPP): *rate designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies by imposing a pre-specified high rate for a limited number of days or hours*

Demand Bidding & Buy-Back: *demand-side resource bids into a wholesale electricity market to offer load reductions at a price at which they are willing to curtail or demand-side resources identify how much load they are willing to curtail at a utility-posted price*

Demand Response: *changes in electric usage by demand-side resources from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized*

Demand Side Management: *all activities or programs undertaken to influence the amount and timing of electricity use*

Direct Load Control: *demand-side management that is under direct remote control of the T&D utility or system operator on short notice. It is the magnitude of customer demand that can be interrupted at the time of the Regional Council seasonal peak by direct control of the System Operator by interrupting power supply to individual appliances or equipment on customer premises. This type of control usually reduces the demand of residential customers.*

Dispatchable: *demand-side resource curtails according to instruction from transmission* *authority*

Economic: *demand-side resources offer to provide load reductions at a price to displace generation resources*

Emergency: *demand-side resource curtails during system and/or local capacity constraints*

Energy Efficiency: *permanent changes to electricity usage through replacement with more efficient end-use devices or more effective operation of existing devices*

Energy-Price: *demand-side resource bids to curtail load for scheduling or dispatch and displaces generation resources; penalties are assessed for noncompliance*

Energy-Voluntary: *demand-side resource curtails voluntarily when offered the opportunity to do so for compensation, but noncompliance is not penalized*

Internal Demand: *Is the sum of the metered (net) outputs of all generators within the system and the metered line flows into the system, less the metered line flows out of the system. The demands for station service or auxiliary needs (such as fan motors, pump motors, and other equipment essential to the operation of the generating units) are not included. Internal Demand includes adjustments for utility indirect demand response programs such as conservation programs, improvements in efficiency of electric energy use, rate incentives, and rebates.*

Interruptible Load: *curtailment options integrated into retail tariffs that provide a rate discount or bill credit for agreeing to reduce load during system contingencies. It is the magnitude of customer demand that, in accordance with contractual arrangements, can be interrupted at the time of the Regional Council's seasonal peak by direct control of the System Operator or by action of the customer at the direct request of the System Operator. In some instances, the demand reduction may be effected by direct action of the System Operator (remote tripping) after notice to the customer in accordance with contractual provisions. For example, demands that can be interrupted to fulfill planning or operating reserve requirements normally should be reported as Interruptible Demand.*

Load as a Capacity Resource: *demand-side resources that commit to pre-specified load reductions when system contingencies arise*

Non-dispatchable: *demand-side resource curtails according to tariff structure, not instruction from transmission authority*

Net Internal Demand: *Equals the Total Internal Demand reduced by Direct Control Load Management and Interruptible Demand.*

Net Energy to Load: *Net Balancing Authority Area generation, plus energy received from other Balancing Authority Areas, less energy delivered to Balancing Authority Areas through interchange. It includes Balancing Authority Area losses but excludes energy required for storage at energy storage facilities.*

Non-Spin Reserves: *demand-side resource not connected to the system but capable of serving demand within a specified time*

Real Time Pricing (RTP): *rate in which the price for electricity typically fluctuates hourly to reflect changes in the wholesale price of electricity on either a day-ahead or hour-ahead basis*

Regulation: *demand-side resources responsive to Automatic Generation Control (AGC) to provide normal regulating margin*

Reliability: *demand-side resources supplement generation resources to offer load relief to resolve system and/or local capacity constraints*

Spinning Reserves: *demand-side resource that is synchronized and ready to serve additional demand*

Standby Demand: *The demand specified by contractual arrangement with a customer to provide power and energy to that customer as a secondary source or backup for an outage of the customer's primary source. Standby Demand is intended to be used infrequently by any one customer.*

Total Internal Demand: *equals the sum of the Internal Demand and the Standby Demand*

Time-of-Use (TOU): *rate with different unit prices for usage during different blocks of time within a 24-hour day*

Time-Sensitive Pricing: *rate structure designed to modify consumption behavior during peak periods through pricing*

Transmission Tariff (4CP): *rate in which interval metered customers reduce load during summer coincident peaks as a way of reducing transmission charges*