Demand Response Discussion
For the
2007 Long-Term Reliability Assessment

North American Electric Reliability Corporation
Reliability Assessment Subcommittee

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1. Introduction

Demand Response is increasingly viewed as an important tool for use by the electric utility industry in meeting the growing demand for electricity in North America. Demand Response 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 programs. This Demand Side Management evaluation is concentrated on reliability assessment of the impacts of Demand Response and therefore, focused on peak demand reduction rather than overall energy reduction. The long-term reliability benefits include reducing supply-side and transmission requirements to meet internal demand as it becomes a resource that can supplement reserves, along with operational reliability benefits providing operating reserve and flexibility.

Demand Response programs generally require substantial investment in advanced metering to enable the ability to send a signal, measure response and validated participation as well as they can be deployed for operational reserves as well as planning reserves. This investment must be recognized along-side other investments as part of overall bulk power system rejuvenation. Therefore, increased certainty on the predictability, especially for voluntary programs, is required as part of the justification of these investments.

For purposes of this report, the North American Electric Reliability Corporation (NERC) will use the same definition of Demand Response as proposed by the U.S. Department of Energy in its February 2006 Report to Congress[1pp.viii] and adopted by the Federal Energy Regulatory Commission (FERC) in its August 2006 "Assessment of Demand Response and Advanced Metering"[1]:

> *"Changes in electric usage by end-use customers 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 prices or when system reliability is jeopardized[2].*

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[1] FERC Staff August 2006 Report: "Assessment of Demand Response & Advanced Metering" http://www.ferc.gov/legal/staff-reports/demand-response.pdf#xml=http://search.atomz.com/search/pdfhelper.tk?sp_o=1,100000,0

[2] U.S. Department of Energy, "Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them:" A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005, February 2006 (February DOE EPAct Report). http://www.oe.energy.gov/DocumentsandMedia/congress_1252d.pdf

FERC noted that Demand Response using this definition can be divided into two categories: incentive-based demand response and time-based rate progrms. Each of these programs has unique aspects with respect to the electric utility industry's ability use the associated programs to reliably plan and operate the bulk power system.

The FERC suggests[1] *"The potential immediate reduction in peak electric demand that could be achieved from existing demand resources is between three and seven percent of peak demand in most regions."* This represents a significant resource for meeting demand using existing Demand Response programs. Expanding the penetration of these programs or designing new ones may result in an even greater resource impact.

2. NERC Data

NERC collects two quantities for on-peak megawatts (MW) for Seasonal (Biannual for Summer & Winter) and Long-Term (10 years) Reliability Assessment Reports: Direct Control Load Management and Interruptible Demand.

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As NERC's reports are forward-looking, the remainder of utility DSM programs is captured as part of the Internal Demand, defined as:

> **Internal Demand[3]**: 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. (Note: please use integrated hourly demand values.)
>
> *Internal Demand includes adjustments for utility indirect demand-side management programs such as conservation programs, improvements in efficiency of electric energy use, rate incentives, and rebates*(**emphasis added**). Internal Demand should not include Stand-by Demand and should not be reduced by Direct Control Load Management or Interruptible Demand.

Respondents to NERC's Seasonal and Long-Term Reliability Assessment data requests, modify the demand curve to accommodate a variety of demand response programs (such as time of use, real-time pricing, etc.) which is specifically helpful when forecasting future Internal Demand. To afford comparative analysis, these same quantities are also collected as part of the forecasted seasonal Summer/Winter Reliability Assessment data requests.

As the industry's use of Demand Response changes, NERC's data collection and impact assessment of these programs will change highlighting those which have an impact on bulk power system reliability.

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[3] NERC: "Instructions for NERC Summer Assessment Data Reporting"

3. The Impact of Demand Response on Reliability

To evaluate the relative impact of Demand Response on reliability, it is first best to provide a suitable categorization of the various programs currently deployed. Figure 1 provides a graphic illustration of Demand Response Programs. Though not exhaustive, it provides a basis for the discussions below.

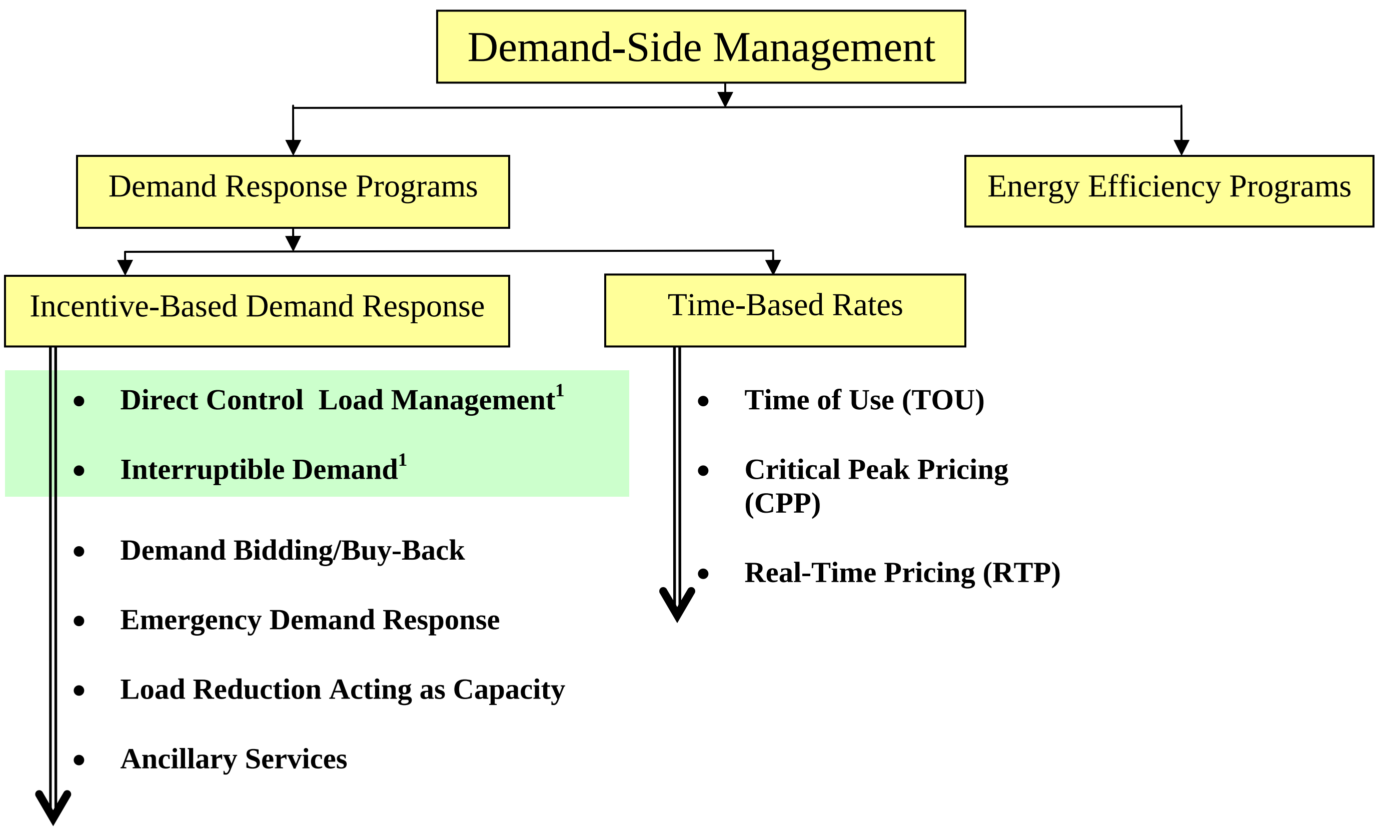

Figure 1: DSM Programs: Focused on Demand Response

[1] Data on these Demand Response Programs are collected by NERC for Seasonal and Long-Term Reliability Assessments

Below is a brief description of the Demand Response subcategories categorized as described in FERC's report[4] . In cases where data is collected for the seasonal and long-term reliability assessments, the program description was modified to reflect NERC's

[4] FERC Staff August 2006 Report: "Assessment of Demand Response & Advanced Metering" Chapter IV, Existing Demand Response Programs and Time-Based Rates

nomenclature. Comments on how each program may impact bulk system reliability also provided. In some cases, the demand response programs are helpful for short-term reliability measures, though unclear regards the long-term impacts on reliability. Further, as with any demand-side management program, experience is needed to determine program requirements and expected demand resource available to manage the balance of transmission, supply and demand. The impact of demand response on this balance and bulk power system reliability requires further study.

Further, many of the programs are not unique to organized markets and can be applied in any electric utility setting.

3.1. Incentive-Based Demand Response Programs

These programs include an inducement or incentive for customer participation and they provide an active tool for load-serving entities, electric utilities or grid operators to manage their costs and maintain reliability. Some of the incentive-based programs that exist are:

- Direct Control Load Management
- Interruptible Demand
- Demand Bidding/Buyback
- Emergency Demand Response
- Load Reduction Acting as Capacity
- Ancillary-Service Market

Each of these is described below along with their associated reliability benefits.

3.1.1. Direct Control Load Management[5]

NERC's Seasonal and Long-Term Reliability Assessments collects data on Direct Control Load Management, defined as:

> *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. Direct Control Load Management as reported here does not include Interruptible Demand.*

Direct control load management programs refer to programs where the utility or system operator remotely shuts off or cycles a customer's equipment on short notice to address system or local reliability contingencies in exchange for an incentive payment or bill credit[6]. These

[5] NERC: "Instructions for NERC Summer Assessment Data Reporting"

programs have been in place for many years and utilities and system operators have gained sufficient experience to reflect them in both operating procedures and resource plans. The actual benefits vary by customer type, geography and climate. Therefore, expanding application of the program must be focused on experience to obtain the desired reliability benefits. As existing programs are expanded or new programs created, their actual characteristics should be factored into planning and operating activities.

3.1.2. Interruptible Demand[5]

NERC's Seasonal and Long-Term Reliability Assessments also collects data Interruptible Demand, defined as:

> *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. Interruptible Demand as reported here does not include Direct Control Load Management.*

Customers on Interruptible Demand programs receive a discount or bill credit in exchange for agreeing to reduce load during system events. If customers do not curtail, they can be penalized. Note that Interruptible Demand Programs are different than Emergency Demand Response and Load Reduction Acting as Capacity program alternatives because they are offered by a load-serving entity or electric utility which implements the program. The application of Interruptible Demand programs is used, though not exclusively, for customers who do not have obligations to provide service (Hospitals, schools, etc.) or 24/7 continuous process operations. Though Interruptible Demand programs have been in place for decades, there is concern about the sustainability and reliability of the resource. For example, industry experience has been an expected participant loss of 3%-5% each time Interruptible Demand programs are exercised. Therefore, long-term assumptions on actual program levels must be done with care.

3.1.3. Emergency Demand Response Programs

Emergency Demand Response programs provide incentives for customers to reduce loads during reliability events, though the curtailment is voluntary. No penalty is assessed if customers do not curtail, and the rates are pre-specified, though no capacity payments are received. These rates are typically offered by Independent System Operators/Regional Transmission Organizations (ISO/RTO), though they are also offered by electric utilities. These programs are voluntary and part of emergency procedures. Generally, Emergency Demand Response is not included in Internal Demand data and NERC does not collect this data for its seasonal and long-term assessments. Operators can not easily predict load curtailment amounts, and planners do not attempt to forecast their impact in the future.

3.1.4. Load Reduction Acting as Capacity

Customers commit to providing specific load reductions during events in return for payments and are penalized if they do not comply. They offer a firm, quickly deployed resource (both emergency operating procedure and a mid- to long-term supply option) which can be forecasted for operations and planning. Operating experience is needed to forecast the affect on short-term and long-term bulk power system reliability.

3.1.5. Demand Bidding/Buyback Programs

Demand Bidding/Buyback Programs enable large consumers to offer specific bid or posted prices for specified load reductions. Customers stay at fixed rates, but receive higher payments for load reductions when the wholesale prices are high. There is ongoing discussion to determine the entities responsible to pay successful customer bidders. Until this review is complete, it is difficult to determine the operational and planning reliability benefits.

3.1.6. Ancillary Services

In some jurisdictions, this program is called Load Acting as a Resource (LaaR). Consumers bid load curtailment for operating (i.e. spinning) reserves. Successful bids are paid as standby reserves and if required are paid spot market energy prices to curtail. To participate, customers are pre-qualified having under-frequency relays set by the electric utility, include integral demand recorders and must be able to curtail load quickly when events occur typically provided in minutes rather than hours. This is juxtaposed to longer duration response for peak-shaving or price signal responses. This program is focused on operational reliability as a high probability resource, though planners can deploy similar concepts measuring long-term and seasonal reliability when evaluating standard criteria (i.e. N-1, etc.) and reserves.

3.2.Time-Based Rate Programs

In this category of Demand Response Programs which have recently received high level of attention for their character to enable the linking of retail and wholesale markets. Retail consumers receive a price signal reflecting the costs of production and delivery which provides a vehicle to deploy resources more efficiently. This characteristic, as the programs are generally tailored for mass markets, has the potential to reduce or shape demand to balance electricity use and overall costs. There are three highlighted Time-Based Rate Programs:

- Time of Use Rates (TOU)
- Critical Peak Pricing (CPP)
- Real-Time Pricing (RTP)

3.2.1. Time-of-Use Rates (TOU)

The most prevalent time-varying program for residential electric consumers, Time-of Use (TOU) rates are pre-set rates offered in a wide variety of time-periods: from seasons to time-of-day depending on the desired application. The pre-set rates reflect underlying costs for production in hopes that consumers will reduce/curtail their use during the higher priced time-periods. Many utilities now require their larger customers to use TOU rates. To aptly deploy TOU, investment in meters is required to enable time-stamped billability. Consumers can change their electricity use behavior if price differentials are substantial. There is a multifarious experience with TOU rates with variety levels of success, as the results can be hard to predict. The load reduction associated with TOU programs tends to be reflected in actual recorded loads and embedded in load forecasts.

3.2.2. Critical Peak Pricing (CPP)

A new form of TOU relies on very high prices during critical peaks rather than average TOU rates. The rates are pre-set, but dispatched dynamically on short notice when needed. Because it is price-based to reflect extreme system stress, CPP rates are equally a reliability based demand response vehicle. Data indicates that consumers do react to reduce/curtail load during the system stress events if appropriate price signals are sent through the CPP rate. As most proposed CPP programs are currently voluntary, more operating experience is needed. Currently the character of penetration and customer churn rate uncertainty makes it hard to determine the reliability benefits for long-term assessment.

3.2.3. Real-Time Pricing (RTP)

Prices in this program vary continuously directly reflecting wholesale prices are not pre-set and are provided hourly and/or day-ahead for pre-planning. It provides a direct link between wholesale and retail markets providing a price-responsive nature to the market and can also enable reduced unit construction as planners and operators can depend on reductions of demand during high-priced hours. As with CPP rates, RTP programs are likely currently voluntary, again making the impact uncertain until further experience is gained by system operators.

4. Conclusion

There is a large potential for demand reduction and subsequent reliability benefits of Demand Response as noted in FERC's report[6]. There is a need to gain operating and planning experience with the specific attributes and the reliability of a number of newer programs to fully appreciate their full potential and clarify the uncertainty associated with the potential reliability benefits. Further, significant infrastructure investment is required and, therefore, it is important to understand the scalability of pilot projects reflecting reliability improvements.

The treatment of Demand Response as it should be incorporated in resource adequacy assessment needs to be better understood. In some cases, it may be best to consider some of the programs like committed resources, while other programs as uncommitted. It is important to understand how fast the programs will grow over the next decade, the impact of customer choice on program participation. These are key characteristics required to ensure that the reliability benefits can be assessed, and reflected appropriately, without double-counting both as internal demand and potential resource.

NERC will continue to follow Demand Response programs to determine the necessary enhancements in data collection along with supply, transmission and demand forecasting to accurately reflect these critical programs in Seasonal/Long-Term Reliability Assessments.

As required, the Reliability Assessment Subcommittee will provide feedback to NERC's Standard development process on Demand Response resources, their character and best practices to ensure that no encumbrance in program deployment is experienced and Demand Response resources are provided appropriate acknowledgement in meeting reliability standards.

[6] FERC Staff August 2006 Report: "Assessment of Demand Response & Advanced Metering"