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Retail Demand Response in Southwest Power Pool

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Environmental Energy Technologies Division

January 2009

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Prepared for the
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Acronyms and Abbreviations

A/C	Air Conditioners
AMI	Advanced Metering Infrastructure
AS	Ancillary Services
BA	Balancing Authority
BDDR	Block Dispatch Demand Response
CBL	Customer Baseline Load
CPP	Critical Peak Pricing
DAM	Day-Ahead Market
DLC	Direct Load Control
DOE	U.S. Department of Energy
DR	Demand Response
EIA	Energy Information Administration (DOE)
EIS	Energy Imbalance Service
EDR	Emergency Demand Response
EEA	Electricity Emergency Alert
FERC	Federal Energy Regulatory Commission
HP	Horsepower
IOU	Investor Owned Utility
IRC	ISO/RTO Council
ISO	Independent System Operator
LMP	Location-based Marginal Price
LBNL	Lawrence Berkeley National Laboratory
LSE	Load-Serving Entity
MISO	Midwest Independent System Operator
MP	Market Participant
MRO	Midwestern Reliability Organization
MWG	Market Working Group
M&V	Measurement & Verification
NERC	North American Electric Reliability Corporation
OATT	Open Access Transmission Tariff
PUC	Public Utility Commission
PRR	Protocol Revision Request
RE	Regional Entity
RFC	Reliability First Corporation
RTO	Regional Transmission Organization
RTP	Real Time Pricing
SERC	Southern Electricity Reliability Council
SPP	Southwest Power Pool
VDDR	Variable Dispatch Demand Resource
TO	Transmission Owner

Abstract

In 2007, the Southwest Power Pool (SPP) formed the Customer Response Task Force (CRTF) to identify barriers to deploying demand response (DR) resources in wholesale markets and develop policies to overcome these barriers. One of the initiatives of this Task Force was to develop more detailed information on existing retail DR programs and dynamic pricing tariffs, program rules, and utility operating practices. This report describes the results of a comprehensive survey conducted by LBNL in support of the Customer Response Task Force and discusses policy implications for integrating legacy retail DR programs and dynamic pricing tariffs into wholesale markets in the SPP region.

LBNL conducted a detailed survey of existing DR programs and dynamic pricing tariffs administered by SPP's member utilities. Survey respondents were asked to provide information on advance notice requirements to customers, operational triggers used to call events (e.g. system emergencies, market conditions, local emergencies), use of these DR resources to meet planning reserves requirements, DR resource availability (e.g. seasonal, annual), participant incentive structures, and monitoring and verification (M&V) protocols.

Nearly all of the 30 load-serving entities in SPP responded to the survey. Of this group, fourteen SPP member utilities administer 36 DR programs, five dynamic pricing tariffs, and six voluntary customer response initiatives. These existing DR programs and dynamic pricing tariffs have a peak demand reduction potential of 1,552 MW. Other major findings of this study are:

- About 81% of available DR is from interruptible rate tariffs offered to large commercial and industrial customers, while direct load control (DLC) programs account for ~14%.
- Arkansas accounts for ~50% of the DR resources in the SPP footprint; these DR resources are primarily managed by cooperatives.
- Publicly-owned cooperatives accounted for 54% of the existing DR resources among SPP members. For these entities, investment in DR is often driven by the need to reduce summer peak demand that is used to set demand charges for each distribution cooperative.
- About 65-70% of the interruptible/curtailable tariffs and DLC programs are routinely triggered based on market conditions, not just for system emergencies. Approximately, 53% of the DR resources are available with less than two hours advance notice and 447 MW can be dispatched with less than thirty minutes notice.
- Most legacy DR programs offered a reservation payment ($/kW) for participation; incentive payment levels ranged from $0.40 to $8.30/kW-month for interruptible rate tariffs and $0.30 to $4.60/kW-month for DLC programs. A few interruptible programs offered incentive payments which were explicitly linked to actual load reductions during events; payments ranged from 2 to 40 cents/kWh for load curtailed.

1. Introduction

The Federal Energy Regulatory Commission (FERC) has expressed ongoing interest and support for ensuring comparable treatment of demand-side resources in organized wholesale electric markets administered by regional transmission organizations and independent system operators (FERC 2008b). Regional state organizations are also interested in ensuring that legacy DR resources are capable of participating effectively in emerging wholesale markets. However, the market data available regarding characteristics and operational features of DR resources are often insufficient to support policymakers in their assessment of opportunities and barriers. This study provides baseline information on the status, characteristics, barriers and opportunities for DR resources in the SPP region.

In its September 26, 2006 order, the Federal Energy Regulatory Commission (FERC) directed the Southwest Power Pool (SPP) to either file changes to its tariff allowing demand response (DR) resources to provide imbalance services in its Energy Imbalance Services (EIS) market or show cause for not making changes to the tariff by identifying the specific barriers and issues preventing such market participation. In response to FERC's order, SPP has filed four status and compliance reports regarding DR resources. In its first filing (August 2007), SPP noted that "while there are various aspects of the EIS Market that can currently accommodate various demand resources, there are other aspects that complicate further incorporation into the market." Specifically, SPP identified particular concerns related to the regulated retail nature of some of the potential participants that can offer DR resources.

In order to address these concerns, SPP has undertaken the following activities:

- established a Customer Response Task Force (CRTF) to explore the potential for incorporating DR resources in future markets;
- established a Demand Response Task Force (DRTF) under the Market Working Group (MWG) to assess the development of an economical method for controllable load to participate in the EIS market;
- started work with the ISO/RTO Council (IRC) on two initiatives to advance DR participation in wholesale energy markets; and
- sponsored a Demand Response Educational Forum in July 2008.

Recognizing that retail DR resources in SPP were not particularly well characterized, the CRTF approached the Lawrence Berkeley National Lab (LBNL) for help in planning and fielding a DR survey.[1] The goal of this project was to develop a comprehensive inventory of retail DR programs, dynamic pricing tariffs, and voluntary DR programs in the SPP footprint. This report is organized as follows. Section 2 provides an overview of the wholesale and retail electricity markets in the SPP footprint while Section 3 describes the DR program survey approach and

[1] With funding from DOE, LBNL has provided technical assistance to various regional demand response efforts including the New England Demand Response Initiative (NEDRI), Mid-Atlantic Distributed Resource Initiative (MADRI), Midwest Demand Resource Initiative (MWDRI), and the Pacific Northwest Demand Response Project (PNDRP). In 2007, LBNL assessed and characterized retail DR programs in the Midwest ISO foot-print (Bharvirkar et al 2008). This report is the latest in a series of studies that aim to educate and provide valuable information on DR resources to policymakers.

objectives. Sections 4 and 5 present survey results. Barriers to participation of retail DR in SPP wholesale markets are discussed in Section 6. Key findings and conclusions are discussed in Section 7, and recommendations for SPP management are provided in Section 8.

2. Wholesale and Retails Electricity Markets in SPP

The Southwest Power Pool (SPP) is one of nine Regional Transmission Organizations (RTO) approved by FERC to ensure reliable supplies of power, adequate transmission infrastructure, and competitive wholesale prices of electricity. SPP covers a geographic area of 255,000 square miles and manages transmission in Arkansas, Kansas, Louisiana, Missouri, New Mexico, Oklahoma, and Texas (see Figure 1). The SPP footprint includes 16 balancing authorities and 40,364 miles of transmission lines serving over 4.5 million customers and a system peak demand of over 43,000 MW. SPP's membership includes investor-owned utilities, municipal systems, generation and transmission cooperatives, state authorities, independent power producers, power marketers, and independent transmission companies.

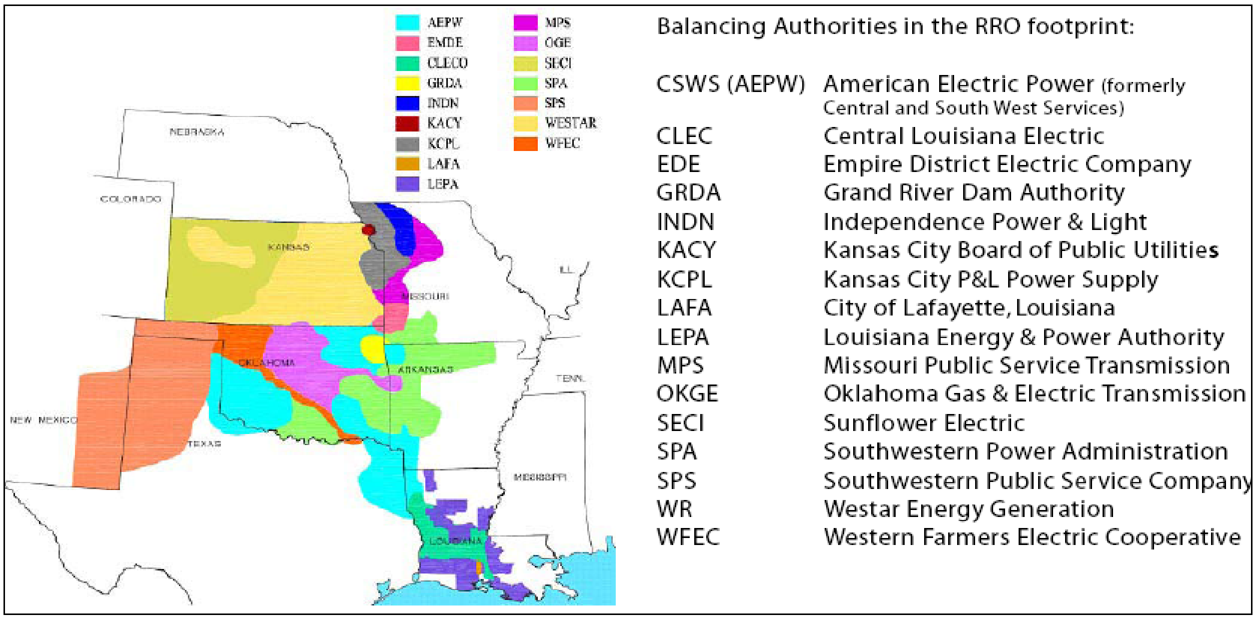

Figure 1. Southwest Power Pool Region Footprint and Balancing Authorities[2]

The SPP region currently has a reserve margin (i.e. generation capacity in excess of peak demand) of 14,074 MW (33%). As of end-2007, the composition of generating capacity in SPP was 54% natural gas-fired.[3] In 2007 there was another 31,000 MW of active generation interconnection requests, of which over three-quarters are for wind projects. SPP's Transmission Expansion Plan (STEP) reflects the need to accommodate new generation and maintain reliability and availability of existing generation, with some $2.2 billion of transmission investment scheduled for the period 2008-2017.[4]

[2] http://www.spp.org/publications/SPP_Footprints.pdf - Note that Central and Southwest Services (CSWS) is now Central and Southwest Corporation (CSW).

[3] 2007 State of the Market Report Southwest Power Pool, Prepared by Boston Pacific Company, Inc., External Market Advisor for the Southwest Power Pool, April 24 2008. http://www.spp.org/publications/2007_State_of_Market_Report.pdf

[4] SPP Transmission Expansion Plan 2008-2017 – Public Version" Prepared by SPP RTO Staff SPP Engineering Planning ("STEP"), Approved by the SPP Board of Directors on January 29, 2008. http://www.spp.org/section.asp?group=1155&pageID=27

2.1 Wholesale Markets in the Southwest Power Pool

SPP administers an Energy Imbalance Service (EIS) market; participation in this market is mandatory for all balancing authorities, transmission owners, and generators in the SPP footprint. All real-time resource or load imbalances are settled using the EIS Market. However, Market Participants can decide whether to dispatch their own resources (i.e. power plants and/or bilateral contracts) or make their resources available for SPP to dispatch via the EIS Market.

In 2007, EIS market sales were 13.2 million MWh, roughly 8% of total power transactions within the EIS market footprint, with a total value of $670 million.[5] The independent Market Monitor concluded that there were trade benefits (e.g., production cost savings) of over $100 million in the first 11 months of operation in the EIS market, mostly due to dispatch of more efficient, lower-priced units to provide imbalance energy than would have been the case if each Balancing Authority had self-provided its imbalance requirements.[6]

SPP's Market Working Group (MWG) has reviewed the market designs of other organized markets and is considering whether to implement a Day-Ahead Market (DAM) and Ancillary Services Markets (ASM). A cost-benefit study is underway, including modeling of the SPP market over the period 2009-2016 to determine regional benefits. The modeling process will include simulating participation of DR at various levels (i.e., DR resources account for 0.5 % to 1.8% of system peak demand). The cost-benefit study will be broadly circulated to SPP stakeholders and will help inform SPP members whether to pursue additional market development.

2.1.1 DR Participation in SPP Wholesale Markets

In June 2007, the SPP Market Working Group established a Demand Response Task Force (DRTF), which was charged with considering how demand response might be incorporated into the EIS market, coordinating with utilities, state commissions, and other SPP working groups on DR, and drafting protocol revisions and tariff language as needed to incorporate viable forms of demand response into the EIS market. After reviewing industry best practices on DR participation in real-time markets, the DRTF recommended a focus on what MISO refers to as DRR Type II resources – that is, controllable loads, either loads with behind-the-meter generation or loads with the ongoing capability to meet specific reduction amounts based on dispatch instructions. These loads are capable of self-scheduling or being scheduled on a five-minute basis and can be committed and dispatched similar to generation resources.

The DRTF considered two types of controllable loads - Variable Dispatch DR (VDDR), which primarily consists of behind-the-meter generation fitted with SCADA-equivalent real-time telemetry, and capable of offering-in on a five-minute basis, and Block Dispatch DR (BDDR), which consists of fixed blocks of interruptible load each with a distinct price. BDDR is dispatchable only at hourly intervals, and requires after-the-fact interval metering for

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[5] SPP EIS Market Footprint differs from the SPP RTO Footprint by the consumption of several entities which are SPP Balancing Authorities but are not SPP EIS Market Participants

[6] http://www.spp.org/publications/EIS%20Trade%20benefit%20report.pdf

performance evaluation. Settlement is possible only at the balancing authority level, as BDDR loads would not be fitted with real-time telemetry.

In August 2008, the DRTF concluded that it would accommodate only the VDDR resource in the existing EIS market, by virtue of its dispatchability within five minutes, interval metering requirements, and ability to accommodate rapid ramp-up and ramp-down. Tariff language to accommodate VDDR into the EIS market has been developed and was approved by MWG in August 2008. Pending development of other wholesale markets to be operated by SPP (e.g., DAM or AS markets), there are no plans to consider other DR resources at the regional level.[7]

2.2 Retail Electricity Markets in the SPP Footprint

SPP Members include many different Market Participants from cooperatives to a federal power-marketing agency (see Table 1). Five investor-owned utilities (American Electric Power, Oklahoma Gas and Electric, Westar Energy, Inc, Southwestern Public Service Company, and Kansas City Power & Light) account for about 75 % of the energy transactions in the SPP market, with rural cooperatives accounting for most of the current demand response activity.

Table 1. Southwest Power Pool Membership Composition[8]

Type of Entity	Number of Entities
Investor-owned utilities (IOU)	12
Cooperatives	11
Municipal utilities	8
State Agencies	2
Power Marketers	11
Independent Power Producers	4
Independent Transmission Companies	2
TOTAL	**50**

Balancing authorities provide ancillary services and coordination in SPP (see Table 2). As of 2007, the total non-coincident peak demand in SPP is 42,884 MW and the generation capacity is 56,050 MW - yielding a reserve margin of ~31% across SPP. However, the reserve margin varies substantially among the balancing authorities with highest (113%) for SWPA and lowest (-8%) for LEPA.

[7] PRR 176 Recommendation Report: Demand Response in the SPP EIS Market. http://www.spp.org/publications/MWG082208Minutes.pdf

[8] SPP membership at the time of our survey; recently three entities from Nebraska have joined SPP. http://www.spp.org/section.asp?pageID=4

Table 2. Balancing Authorities in SPP Region

Balancing Authority	Type of Entity	Sales (million MWh)	Non-coincident Peak Demand (MW)	Generation Capacity (MW)	Reserve Margin (%)
American Electric Power West	IOU	46.98	10,013	13,713	37
Oklahoma Gas and Electric	IOU	29.85	6,317	8,269	31
Westar	IOU	29.81	6,138	6,603	8
Southwestern Public Service	IOU	27.72	5,044	5,794	15
Kansas City Power and Light	IOU	16.89	3,689	4,612	25
Cleco Power	IOU	10.43	2,104	4,242	102
Missouri Public Service	IOU	9.04	1,999	1,947	-3
Southwestern Power Administration (SWPA)	Federal	7.50	1,632	3,475	113
Western Farmers Electric	Coop	7.09	1,369	1,328	-3
Empire District	IOU	5.51	1,177	1,377	17
Sunflower Electric	Coop	5.17	995	1,375	38
Grand River Dam Authority	State	4.48	909	1,607	77
Kansas City BPU	Muni	2.60	512	743	45
City of Lafayette	Muni	2.03	478	493	3
Independence City P&L	Muni	1.19	308	288	-6
Louisiana Energy and Power Authority (LEPA)	State	1.00	200	184	-8
SPP TOTAL		**20.73**	**42,884**	**56,050**	**31**

3. Survey Objectives and Approach

The primary objectives of the survey were to characterize existing retail DR programs and dynamic pricing tariffs administered by SPP member utilities and identify potential barriers to utilization of DR resources in wholesale and retail markets. The survey template was developed by LBNL with input from the SPP Customer Response Task Force (CRTF). The SPP CRTF transmitted the survey to all SPP members and requested their cooperation. LBNL compiled the survey data, conducted follow-up interviews (including interviews with several distribution cooperatives whose wholesale requirements were served by SPP members) and quality assurance/consistency checks on survey responses, supplemented survey data with information from other sources, and analyzed the survey results.

Utilities were asked to provide information on retail DR programs (e.g., interruptible, direct load control or DLC, emergency programs, and demand bidding programs where events are triggered by high prices), dynamic pricing tariffs (including Real Time Pricing, or RTP; and Critical Peak Pricing, or CPP), and voluntary DR programs (i.e., a program where customers voluntarily participate and make a "best efforts" attempt to curtail load when requested but are not compensated).

Interruptible rate programs provide a rate discount or bill credit to the customer for curtailing or shedding load upon request. Typically, interruptible programs are offered to larger industrial and commercial customers and often involve penalties if the customer fails to curtail load when requested to do so. DLC programs involve an end-user (typically, residential or small commercial) who agrees to allow their utility to control an appliance or device within certain pre-set limits of frequency and duration. Participants in DLC programs typically receive compensation in the form of bill credits and/or payments based on performance during events. Customers enrolled in a Demand Bidding or Economic DR program offer bids to curtail load based on market prices. These programs are mainly offered to large customers; however, some utilities also allow aggregation of small customer loads.

An RTP tariff provides variable hourly pricing for all hours of the year, while a CPP tariff provides variable pricing only for a relatively few number of hours per year when the utility calls a CPP event. A one-part RTP tariff assesses all volumetric (per kWh) charges based on variable hourly prices. A two-part RTP tariff incorporates a customer baseline (CBL) usage that establishes a long-term average hourly usage profile for each customer. Variable hourly prices are applied only to the differences between actual hourly load and the CBL. A two-part RTP tariff effectively provides a hedge against the implicit price-exposure risk of variable hourly prices as the bulk of a customer's consumption is billed on the customer's otherwise applicable tariff. Hourly prices can be indexed to wholesale energy market prices (i.e. either day-ahead or real-time) or utility marginal costs.

4. Survey Results: Overview of Existing DR Resources

The SPP Retail DR Survey was sent to all 50 SPP members, including utilities, generators, power marketers, and transmission companies.[9] Virtually all of the 30 load-serving entities (LSE) responded to the survey. Among this group, 14 LSEs offered a total of 48 demand response programs and/or dynamic pricing tariffs (see Table 3).

Table 3. SPP Retail DR Survey Response

Type of Entity	Number of Surveys Fielded	Number of Responses Received	Load-Serving Entities with DR Programs	Number of DR Programs and/or Tariffs
Cooperatives	11	11	6	13
Municipal utilities	8	8	1	5
Investor-owned utilities	12	10	7	30
State Agencies	2	2	0	0
IPPs	4	0	N/A	N/A
Power Marketers	11	0	N/A	N/A
Transmission Companies	2	0	N/A	N/A
Total	**50**	**31**	**14**	**48**

4.1 Existing DR Resources

The size of the DR resource is defined as the potential peak load reduction that the utility expects from the DR program or dynamic pricing tariff (this benchmark is consistent with the approach taken by FERC and EIA in earlier surveys). On this basis the utilities reported retail DR resources totaling 1,552 MW, with DR programs accounting for 87% of the total DR resource (see Table 4).

Table 4. Existing DR Resources in SPP

	DR Programs	Dynamic Pricing Tariffs	Voluntary Customer Response Initiatives
Entities with DR Activities	13	5	4
Number of Programs	36	6	6
Potential Coincident Peak Demand Reduction	1,352 MW *(26)*	200 MW *(5)*	N/A
Number of Eligible Customers	382,364 *(30)*	16,886 *(5)*	N/A
Number of Customers Enrolled	63,388 *(27)*	70 *(6)*	N/A

Note: Numbers in parentheses indicate the programs, tariffs, and initiatives that provided this information.

Our survey estimate of the existing DR Resource in the SPP region is consistent with earlier estimates developed by FERC (2006) and somewhat higher than the most recent estimate reported by the ISO/RTO Council (2007) and FERC (2008a). We attribute these differences to the higher response rate of SPP members in our survey. Our estimate of existing DR resources is also considerably higher than the most recent NERC Regional Reliability Assessment (NERC

[9] Fifty entities were SPP members at the time of the survey; three entities from Nebraska have joined SPP recently.

2008). The difference in these aggregate numbers may be definitional, as NERC collected data on DR that is dispatchable by the operator to reduce load. Thus the NERC numbers may exclude Economic/Demand Bidding and Buyback programs as well as Dynamic Pricing Tariffs.

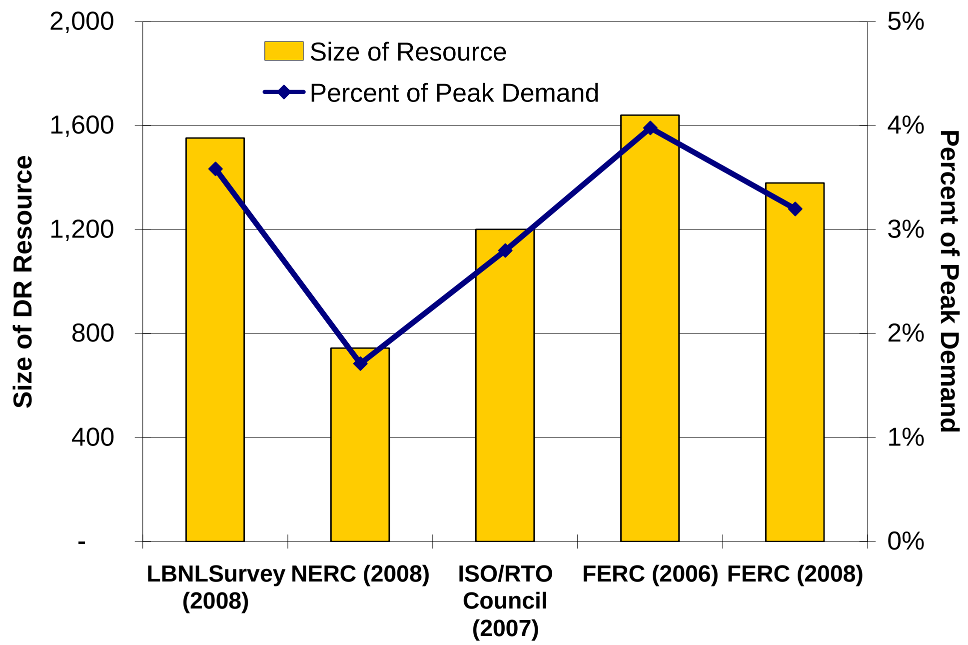

Figure 2. Estimates of existing DR Resources in the SPP Region

There is a large variation in the amount of DR Resources across the seven states partially or wholly contained within the SPP region (see Figure 3). For example, in Louisiana no DR resources were reported while Arkansas (i.e. parts that are contained within the SPP footprint) accounted for ~49% of the total DR resources in the region. Potential load reductions from all DR resources accounted for ~46% of the non-coincident peak demand in Arkansas - one of the highest DR market penetration levels in the US. Across the entire SPP footprint, existing DR resources account for ~3.7% of system peak demand, somewhat lower than the national average.

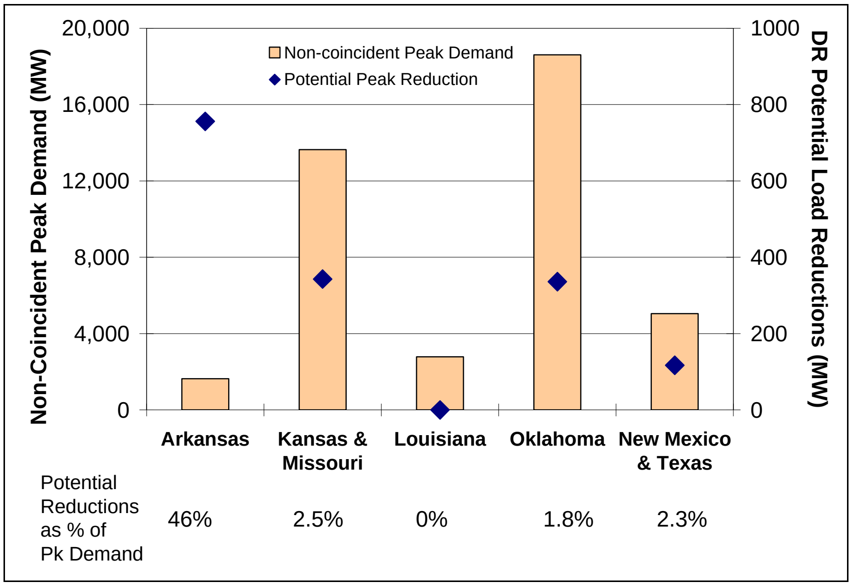

Figure 3. Demand Response Resources by State

Cooperatives account for 80% of the DLC resource and 53% of the interruptible/curtailable resource; the majority of which is located in Arkansas (see Figure 4). Investor-owned LSEs in Missouri, Kansas and Oklahoma account for the bulk of the remaining DR resources in the SPP footprint.

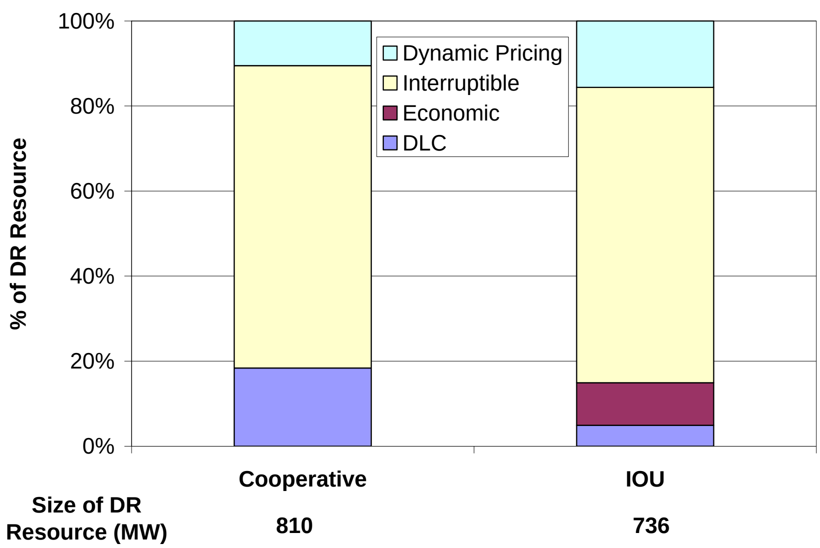

Figure 4. Existing Demand Response Resources by Type of Entity

Large portions of western Arkansas are served by 17 electric distribution cooperatives that also collectively own the generation and transmission assets serving their load. Investment in DR is mainly a result of the need to reduce summer peak demand that determines the demand charge for each distribution cooperative.[10] Transmission network interval load data is shared over the Internet, allowing the distribution coops and their retail customers to anticipate the coincident peak demand day and reduce their demand accordingly. Mass market DR programs such as direct load control for irrigation pumping, household and commercial air conditioners, and water heaters are used extensively in order to minimize non-coincident peak demand and maintain a high load factor.

The very high penetration levels of demand response in Arkansas cooperatives can be traced to three factors: (i) long-term stability in the type of price signals sent; and (ii) sufficient bill savings potential to gain active customer participation and interest; and (iii) avoiding over-payment of incentives, so there is sufficient savings for participants, non-participants, and utility management.

4.2 DR Program Characteristics

The survey requested detailed information on a range of DR program characteristics, including operational triggers, frequency of events, advance notice provided, program duration, participation requirements (e.g. size thresholds, market segments, etc.), communications arrangements, and monitoring and verification protocols. This section discusses these program characteristics and their implications for DR participation in SPP's EIS and planned day-ahead and ancillary services markets.

4.2.1 Operational Triggers

Respondents were asked to describe conditions that triggered the operation of their DR Programs. The options provided in the survey question included maintaining system reliability (e.g., system emergencies), reducing the cost of procuring power during high price periods (e.g., responding to market conditions), addressing local reliability or congestion problems, and meeting contractual obligations.

The dispatch trigger pattern is quite different for DLC and interruptible programs (see Figure 5). Seventy percent of DLC resources are triggered based on market conditions, while only 20% and 41% of DLC resources are dispatched for system emergency and local conditions, respectively. This likely reflects the use of DLC by distribution cooperatives for flattening out their load shape and minimize coincident transmission system peaks, thereby achieving substantial savings in their demand charge.

In contrast, almost 100% of the DR resources available from interruptible programs in the SPP region could be interrupted for system emergencies. Approximately, 67% of interruptible resources could also be dispatched in response to market conditions and 27% could be deployed for addressing local conditions. This is consistent with trends in MISO and elsewhere and suggests that these interruptible tariffs could be reconfigured to be bid into SPP's existing and future wholesale markets.

[10] The bulk power tariff includes a ratcheted demand charge based on each coop's contribution to the previous summer's transmission system peak demand. Large retail customers have interval meters and are subjected to the same ratcheted demand charge structure as distribution coops.

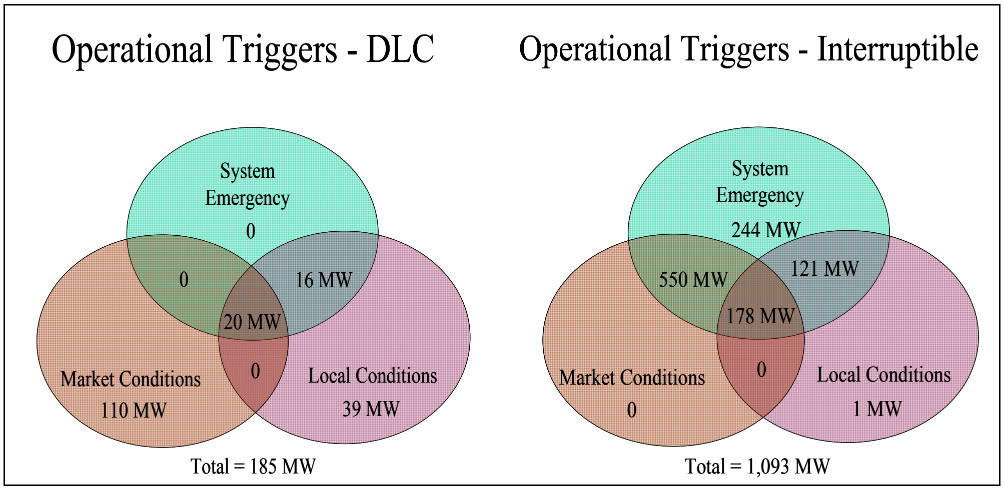

Figure 5. Operational Triggers for Direct Load Control and Interruptible Tariffs in SPP

Several respondents noted that operational triggers are in rapid flux. For example, one cooperative reported that starting in 2008 up to half the allowed hours of operation allowed under Interruptible Load contracts can be for any reason, including economics. This is in contrast to past rules, which restricted interruptions to capacity shortages and exposure to coincident peak demand charges.

4.2.2 Advance Notice Requirements

Advance notice requirements vary considerably across DR Program types (see Figure 6). DLC programs were uniformly reported to have no notice requirements. This lack of advance notice would be a real advantage in configuring DLC resources for SPP's EIS market and potentially in a future AS market, provided the stringent operational requirements are met.

All of the reported Economic/Demand Buyback resources require less than 30 minutes notice, suggesting that this resource as well could be reconfigured for the EIS market. In contrast, about 58% of the DR resources on interruptible tariffs require more than two hours of advance notice, which is unacceptable for the EIS or ancillary services markets but could work for day-ahead energy markets.

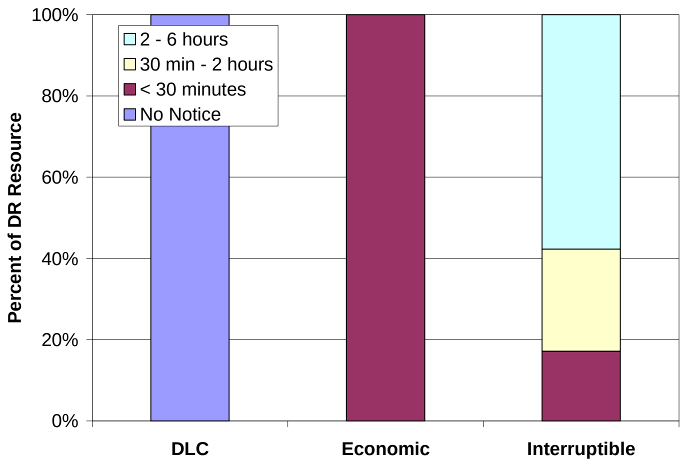

Figure 6. Advance Notice Requirements for SPP DR Programs

4.2.3 Participation Requirements

Respondents reported relatively few minimum requirements for participation in DR Programs. DR programs accounting for 64% of the total DR resource reported no minimum load reduction requirements. This suggests relatively flexible and customer-friendly program rules, which could contribute to rapid scaling-up of DR should sufficient incentives be made available via wholesale or retail markets.

4.2.4 DR incentive payments

Respondents were also asked to report on how participants were compensated for participating in DR programs, as well as the basis for determining incentive levels. We found significant differences in incentive design and compensation levels across cooperatives and IOUs and also across states, and program types. Incentives were provided in three forms:

1. Capacity payments (i.e. $/kW offered per month),
2. Performance payments ($/kWh paid according to a single event)
3. Capacity-performance payment combinations (i.e. both $/kW and $/kWh).

Many cooperatives calculate the incentive for partial or total control of various end uses based on a flat monthly per-kW incentive, converted into a flat monthly incentive based on the control strategy and the coincident demand of the end use. For example, participants in a residential air conditioner load control program might get $5 off on their summer monthly bill, while participants in a water heater load control programs might get $1 off their bill year round.

For larger customers, coops and IOUs offer a choice of firm and non-firm service for specific loads such as pumps or processes. Commercial and industrial customers can access large discounts on the fixed charge for non-firm service, levied as a horsepower or demand charge, in exchange for taking non-firm service. For example, large pumping loads served by a Kansas distribution cooperative would face a monthly firm service charge of $13 per hp ($17.42/kW) but a non-firm charge of only $1.75 per hp ($2.35/kW). Non-firm irrigation pumping loads are controlled on a regular schedule allowing growers sufficient flexibility to work around the hours of interruption.

Only 17 of the 36 DR programs provided information on incentive levels and design. Five DLC and six interruptible programs provide a capacity-type incentive that ranges from $0.3 to $4.6/kW-month and $0.4 to $8.3/kW-month, respectively. Five interruptible tariffs provide only a performance payment ranging from 2 to 40 cents/kWh. One interruptible tariff provided a combination of capacity and performance payment ($1.2/kW-month and $0.20/kWh).

We also asked respondents about the basis used for setting incentive levels for DR programs. Respondents reported that they typically looked at more than one factor in setting incentive levels (see Table 5). Consideration of marginal capacity costs and the cost of a peaking unit (e.g., a natural gas-fired combustion turbine) were used as the basis by DR programs accounting for ~70% of the potential load reductions. Programs accounting for ~18% of the DR resources used the cost of onsite generation as the basis to set incentive levels.

Table 5. Basis for Compensating Demand Response Program Participants

Cost/Compensation Basis	DLC (MW)	Economic (MW)	Interruptible (MW)	TOTAL (MW)
Marginal Capacity Costs (MCC)	39	74	128	241
MCC & Peaking Unit Proxy	16		563	579
MCC & Customer-owned generation			60	60
Peaking unit proxy			63	63
Value of Service			27	27
Cost of customer-owned generation			239	239
Negotiated			8	8
Not Applicable (no incentive)	20			20
Unknown			5	5
Varies for each member coop	110			110
TOTAL	185 MW	74 MW	1,093 MW	1,352 MW

Clearly, opening up SPP's EIS Market to participation by certain types of qualifying DR resources will create an important new benefit stream and provide a new reason for Market Participants to expand existing or develop new DR programs. If SPP establishes additional markets (e.g., Day-Ahead Energy and Ancillary Services), this will further expand opportunities for existing (and new) DR resources.

4.2.5 Recent Performance and Frequency of DR Events

Respondents were asked to report how frequently their DR programs operated, including recent performance. Respondents reported (see Table 6) that DR programs accounting for 96% of the total resource in SPP were deployed at least once in 2007. However, dispatch was relatively infrequent, with ~70% of the DR resources deployed less than five times.

Table 6. Recent Performance of Demand Response Programs

Frequency of DR Events	DLC (MW)	Economic (MW)	Interruptible (MW)	TOTAL (MW)
No events	39	12		51
1 to 5	16	62	864	942
5 to 25	20		8	28
> 25			14	14
Varies by member coop	110			110
Unknown			208	208
TOTAL	185 MW	74 MW	1,093 MW	1,352 MW

It should be noted that DR programs accounting for ~15% of the resource did not provide information about program performance. This infrequent utilization is likely a function of high reserve margins currently enjoyed by many LSEs in the region. However, many respondents indicated that demand growth in their service territories could result in increased DR operations over the next few years.

5. Dynamic Pricing Tariffs and Voluntary Customer Response Activities

In section 4, we focused on DR programs that can be triggered by the distribution utility through either interruption or control requests. We also asked survey respondents about two other types of DR activities – dynamic pricing tariffs and voluntary customer response initiatives - which are described in this section.

5.1 Dynamic Pricing

The survey identified five utilities (3 investor-owned and 2 cooperatives) offering one CPP and five RTP tariffs in four states (Oklahoma, Kansas, Missouri, and Arkansas) in the SPP footprint. Four of the five RTP tariffs were of the two-part design (i.e. only incremental load above a base amount was billed at RTP).

In 2007, a total of 70 customers were enrolled, accounting for 304 MW of peak demand and 200 MW of potential demand reduction. The largest demand reduction achieved as a result of the dynamic pricing tariff was 133 MW when prices reached $0.28/kWh.

Eligibility for participation in dynamic pricing tariffs in all cases was restricted to commercial and industrial customers. All but one of the tariffs operated on a year-round basis, and recruitment was strictly on an "opt-in" basis for all utilities. In most (5 of 6) cases customers taking service on a dynamic pricing tariff were not allowed to participate in other DR programs.

Price notification was by Internet for all five of the RTP tariffs and based on day-ahead wholesale prices. All of the participants had access to their interval load data in some form, with two tariffs offering near real-time interval load data availability and two more offering interval data on a day-after basis. Load impact estimation methods varied, with only half reporting on M&V and several methods reported (e.g., day-matching, econometric, customer baseline).

Only two of the five utilities allowed the forecast load impacts of dynamic pricing to be counted towards Reserve Margin requirements. However, none of the dynamic pricing impacts were considered in scheduling Residual Unit Commitments or meeting real-time imbalance requirements.

5.2 Voluntary Customer Response Initiatives

Six voluntary customer response initiatives were reported by four utilities (two IOUs and two cooperatives) in six states (Oklahoma, Texas, Louisiana, Kansas, Missouri, and Arkansas). One IOU accounted for half of these in three of the states. Recruitment for participation in these initiatives has been through existing account management initiatives and in one case through radio appeals.

Large customers (≥ 750 kW) were typically targeted and requests for load reductions were made via email. No monetary compensation was offered for any of the voluntary DR initiatives. Five of these programs have been called at least once, but none have been evaluated; thus the utility did not provide an estimate of peak demand reduction for this voluntary DR initiative.

6. Barriers to Retail DR

We also conducted follow-up telephone interviews of SPP member utilities, which focused on barriers encountered in implementing or scaling-up demand response activities and suggestions for SPP management.

These interviews revealed considerable disparity in the level of effort focused on demand response implementation across the respondents. The lowest DR program participation levels (on the order of 1-2 % of system peak demand) appear to be a result of either lack of DR programs offered or promoted, an unwillingness on the part of customers to be inconvenienced, or incentives that are set too low to attract participants.

Several municipalities in Oklahoma previously attempted DLC programs that did not work because the air conditioners were too small and thus the cycling caused customer discomfort that was unacceptable, given the incentive levels. Other respondents reported that incentive levels based on marginal capacity costs less program expenses were insufficient to attract and hold customers.

Several municipal and investor-owned utilities reported previous unsuccessful efforts with retail demand response programs. Several utilities had programs "on the books" but with no participants and no active marketing efforts because reserve margins are high at present.

A number of respondents offered suggestions for SPP management to consider that could help overcome barriers to DR. These include:

Technical Assistance - A few respondents suggested that both customers and utility employees should be made aware of the value of DR programs and provided with technical assistance in designing and implementing them. DR is a relatively new concept in SPP and respondents from utilities that crossed several jurisdictions noted that DR participation is much lower in their Southwestern operating subsidiaries than in other areas of the country that they serve.

Education/Information - A number of survey respondents suggested that SPP can play an important role in promoting initiatives such as establishing common terminology for DR and common understanding of DR concepts across the membership. SPP could promote education and awareness about DR programs and facilitate dialogue among stakeholders (e.g., customers, utility management, and regulators) that need to participate and support DR. A regional initiative similar to that undertaken in other regions can provide a versatile platform for informing and facilitating DR policies. Finally, it was suggested that SPP should track and report on DR implementation experience and best practice throughout the region.

Changes to Market Rules - Several respondents suggested that SPP should accelerate efforts to integrate DR resources in SPP's existing wholesale market (EIS). Although some progress has been made by the DRTF, SPP should consider expanding its outreach efforts to Market Participants in order to help identify existing retail DR program participants that might be eligible to offer Variable Dispatch DR (VDDR) resources in the EIS market and expanding eligibility to include Block Dispatch DR (BDDR) resources.

7. Findings and Conclusions

The primary objectives of this study were to provide policymakers, regulators, and other stakeholders in SPP with baseline information on existing DR resources and barriers to integrating retail DR programs in existing and proposed wholesale markets.

Fourteen SPP member utilities reported existing retail DR resources totaling 1,552 MW, of which ~81% comes from interruptible rate tariffs targeted at large industrial and commercial customers. Across the entire SPP footprint, existing DR resources account for ~3.7% of system peak demand. The SPP region has a somewhat lower level of DR participation in retail and wholesale markets compared to other ISOs/RTOs. This may be due to historically high reserve margins, although our interviews with SPP members suggest that lack of awareness of the importance of demand response in reducing costs and increasing market efficiency may also be factors.

We found significant variation among states in the deployment of existing DR resources. For example, in Louisiana, SPP members reported no DR resources, while in Arkansas, potential load reductions from existing DR resources account for ~46% of the non-coincident peak demand. A very strong incentive structure in the form of ratcheted demand charges is one of the main reasons behind the widespread use of DR programs in Arkansas.

We found considerable diversity in DR program characteristics among LSEs. This suggests that integration of existing retail DR programs and tariffs in the SPP market may require significant effort initially to develop consistent program requirements and protocols. At the same time, certain aspects of existing DR programs such as lack of minimum participation requirements, eligibility of on-site generation to participate, and use of multiple operating triggers suggests that existing retail DR program designs are flexible and can be reconfigured to meet the needs of the existing and future SPP wholesale markets.

Retail DR programs operated by distribution cooperatives can provide a potentially large DR resource to the SPP market. The cooperatives account for ~80% of the DLC resource, a large portion (~70%) of which is routinely triggered based on market conditions and require no advance notice prior to dispatch. These cooperatives have already proven to be leaders in configuring their DR programs for optimal economic benefit to customers and may be able to extract additional benefits for their customers from bidding DR resources into existing and emerging wholesale markets.

A few investor-owned utilities are offering voluntary real-time pricing for large customers. However, the reported contributions are small relative to dispatchable DR (200 MW reported vs. 1352 for DR programs), and the forecasted demand reduction from dynamic pricing are not currently included in resource adequacy planning. Some respondents noted that regulators and senior managers at utilities are considering smart meters and Advanced Metering Infrastructure (AMI). Widespread deployment of AMI can allow expansion of dynamic pricing tariffs to more customers.

SPP could help facilitate the development of DR resources and their effective participation in the SPP wholesale markets through activities such as raising awareness of DR benefits and costs, providing technical assistance, and creating a forum for developing consensus among stakeholders (e.g. policymakers, regulators, utilities, and others). In Table 7, we offer a number of suggestions for SPP to consider as part of an action plan that could enhance awareness and promote consideration of DR in wholesale and retail market and system operations.

Table 7. Suggested Activities for SPP to promote Demand Response

Suggested Activity for SPP	Suggested Action Plan and potential next steps
Promote basic standardization, such as common terminology for DR and common understanding of DR concepts across the membership;	1. Consider adopting a DR terminology section within the SPP operating manuals 2. Review existing DR terminology/glossary chapters from PJM, NYISO 3. Begin participating in the NAESB Wholesale DR committee 4. Develop a brochure on DR opportunities for SPP Members
Facilitate awareness building and dialogue among entities that need to participate and support DR	1. Increase participation in ISO/RTO Council (IRC) DR activities 2. Set specific goals and objectives and end states or outcomes for an SPP regional initiative on DR 3. Enter into a dialogue with other ISO/RTO that have participated in regional DR initiatives in order to assess potential value
Identify specific RTO actions that could be taken to support development of more retail DR	1. Consider pro-active efforts, such as pilot projects (e.g., auto-DR, residential smart-stats), to increase opportunities for existing retail DR to bid into SPP wholesale markets 2. Outreach to key distributor groups – e.g., NRECA – to identify most-promising DR opportunities
Track and report on implementation experience in the SPP footprint	1. Actively cooperate with NERC and FERC on DR data gathering for the SPP market 2. Work with state regulators & regional reliability entities to coordinate reliability assessments, resource adequacy planning 3. Prepare case studies that highlight best DR practices, drawing from SPP DR survey results 4. Follow-up on good practice gaps identified in this study, such as lack of standardized M&V procedures

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