International Review of Demand Response Mechanisms

PREPARED FOR

Australian Energy Market Commission

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Executive Summary

The Australian Energy Market Commission (AEMC) has asked us to review how demand response (DR) participates in wholesale electricity markets in a range of jurisdictions, in order to inform its own market design developments regarding demand response participation in Australia's National Electricity Market (NEM).

We have studied wholesale DR participation in six wholesale markets that differ in terms of their geographies and regulatory arrangements, offering a broad cross-section of approaches to DR. Half of these markets have an "energy-only" generation investment model (Singapore, Alberta and ERCOT), while the other half have capacity obligations (PJM, ISO-NE and Ontario) complementing their energy markets. Markets with capacity obligations may not be directly comparable to the NEM, but they have attracted the largest amounts of DR resources, which also participate in wholesale energy and ancillary services markets and may thus provide insights applicable to NEM.

Below we describe our observations about DR participation in wholesale energy markets, followed by ancillary services markets, then capacity markets. Note that in the sections that follow, we describe DR performing three *functions*: energy, ancillary services, and capacity. In contrast, our report is organized so as to distinguish between two different types of *jurisdictions*, which we refer to as "Energy-Only Markets" and "Markets with Capacity Obligations". DR could potentially provide all three functions in any jurisdiction.

Demand Response and the Energy Function

Perhaps the simplest means of enabling DR in energy markets is to establish liquid wholesale markets with transparent wholesale energy prices, which NEM and the other markets (energy-only markets and markets with capacity obligations) we evaluated already do. This enables the largest customers, who may be direct wholesale market participants, to reduce their consumption and save money when they observe prices rising above the maximum value that they obtain from consuming electricity. Other customers may do the same to the extent they are exposed to wholesale spot prices through retail arrangements. We call this "price-responsive load". Though most customers choose to purchase electricity at a fixed price, we see some price-responsive load, especially in energy-only markets with volatile energy prices. Load reductions attributable to price-responsive load in the energy-only markets we surveyed ranged from about 1% of peak load in Texas to more than 2% in Alberta, although the exact amounts are difficult to determine.

Price-responsive load enhances economic efficiency and supports supply adequacy. It does not, however, do so with perfect precision if wholesale prices are volatile and customers' load reductions do not coincide with times of greatest need. To increase precision, loads would have to submit price-responsive bids and allow the system operator to dispatch[1] them in real-time (similar to how generators are dispatched). However, we have observed minimal participation in dispatchable load programs in Alberta and Texas. The lack of customer interest may be explained by the costs to purchase real-time telemetering equipment and the loss of a customer's operational flexibility when the system operator controls its consumption (and charges penalties for deviating) compared to the incremental value available.

We do see substantial amounts of load participating directly in energy markets where DR aggregators (DRAs) are allowed to sell end-users' load reductions as supply, as in PJM and ISO-NE. This supply-side DR model developed first in markets with capacity obligations, where system operators viewed dispatchable loads as a resource they could deploy in emergencies; and where specialized DR providers gained expertise finding and setting up customers with flexible loads, and aggregating them into resources that could compete with generation in capacity markets. We discuss DR performing the "capacity function" in the next section.

As with participation in capacity markets, DR providers' participation in energy markets is also on the supply side: they submit offers to curtail load into day-ahead or real-time markets and earn a market price if they are dispatched. However, the determination of the settlement quantity and price are not as straightforward as for a generator. The quantity is given by the difference between actual consumption during the period in which they are dispatched, and a higher hypothetical baseline level that would have been consumed if the resource had not been dispatched. In US markets, system operators establish baselines according to various methodologies that attempt to estimate the hypothetical consumption, for example based on that customers' historical consumption; Singapore plans to solicit DR providers to nominate their customers' baselines and penalize them if the customer consumes less than the baseline when not dispatched.

As for the settlement price, the locational marginal price would be appropriate if the customer had already bought the power and was now re-selling it. But that is generally not the case: customers only pay for metered load. Therefore the savings in the generation component of the retail price the customer would have paid on the energy not consumed should be deducted from the payment, in order to avoid double counting. Estimating that relevant retail price can be a challenge especially for disparate customers of a DR aggregator, although PJM (and the Midcontinent ISO) have developed ways to do that.

Policymakers may consider enabling supply-side mechanisms to engage the specialized expertise of third party DRAs if they would otherwise face barriers to participating in the market indirectly through agreements with retailers (and sharing some of the value in lowering the retailer's cost to serving the customers' loads). We have not evaluated the extent

[1] We use the term "dispatch" to mean the process by which the system operator directs a resource to operate in a certain way (eg, directs a generator to produce a certain quantity in a particular time interval). In some jurisdictions the term "schedule" is used.

to which there may be barriers to retailer-DRA cooperation or other barriers to DRA participation in the NEM.[2]

One final consideration in incorporating demand response into energy markets is how to achieve efficient price formation that supports efficient operations and investments. Ideally, when generation supplies become tight, demand reductions would clear the market and set energy prices at customers' willingness-to-pay. It is important that rules for determining the system price take proper account of DR, particularly under scarcity conditions. In ERCOT, for example, reforms were introduced to prevent dispatch of emergency DR from depressing the system price.

Demand Response and the Ancillary Services Function

In order to accommodate the sudden loss of a large generator or transmission line, electricity systems need to hold operating reserves. Operating reserves have traditionally been provided by generators that produce less than their maximum output so they can increase their output when deployed in a contingency. However, loads can also provide operating reserves by offering to curtail at short notice. This ability to curtail is clearly valuable for the efficient operation of a power system. PJM, Ontario, Singapore, Alberta and ERCOT allow loads to compete with generation to provide contingency reserves. Loads provide a substantial portion of reserves in several of these markets, including approximately half of the responsive reserve requirement in ERCOT.

Allowing loads to provide ancillary services (AS) is beneficial because it can reduce overall costs. Also, in some circumstances, loads may be able to provide services that most generators cannot. For example, while loads can be curtailed via a signal from the system operator, they can also be curtailed automatically using under-frequency relays. Loads curtailed in this manner respond extremely quickly to contingencies, faster even than a generator on governor response. This fast response has enabled some specialized AS products, such in Alberta and ERCOT.

Some markets also allow loads to provide other AS services, such as regulation (direct system operator remote control to balance supply and demand within a dispatch interval). However, while some markets seem to be moving in the direction of allowing loads to provide regulation, we have not seen substantial participation where this is allowed.

In our review we did not come across significant controversies with respect to DR provision of AS. In particular, we did not encounter controversies about DR baselines in AS markets as we did in energy markets. We note that while DR providers may be technically capable of providing both AS and energy, in any given hour they will only be able to provide one or the other.

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2 Another consideration for enabling DR aggregators to participate as suppliers in the energy market is that they could be dispatched and settled nodally, whereas price-responsive load faces only zonal prices. Nodal dispatch could provide end-users with more localized price signals and give the system operator more control.

Demand Response and the Capacity Function in Markets with a Capacity Obligation or Emergency Standby Programs

In jurisdictions with capacity obligations, DR revenues from capacity payments tend to be much larger than payments for energy or AS. Recent policy developments have focused on participation rules for DR providers that are not available year-round, and how to ensure that DR providers respond to dispatch instructions when called. These issues are more important in capacity markets than in energy markets because capacity markets typically provide payments for being available to respond. In an energy-only market, payment is for actual dispatch rather than availability. It may be easier to measure response to a dispatch signal than it is to determine whether a resource is available to be dispatched if called (though note the concerns over baseline methodologies described above).

Although ERCOT is an energy-only market, its Emergency Reserve Service (ERS) program has some similarities with capacity market DR programs. ERS's predecessor was created following an episode in which firm load was shed. Load shedding may be necessary during a supply shortfall, but it does not distinguish between loads with different willingness to be curtailed. ERCOT created the ERS program to increase the efficiency of future load shedding by first curtailing customers with a relatively low value of lost load. ERS shares several characteristics with capacity market DR programs: it procures DR to respond to system emergencies and pays DR providers an availability payment.

I. Introduction

In some wholesale markets the market design includes elements which aim to incorporate demand response (DR) programs that existed in some form prior to restructuring and the implementation of an organized wholesale market. In other cases, mechanisms for DR to participate in the wholesale market have evolved over time with the aim of making markets more efficient. For example, in markets with a formal capacity mechanism it may be significantly cheaper to procure a given quantity of capacity from a mix of DR and generator providers than it would be to procure the same quantity from generation only.

DR in wholesale electricity markets can refer to four different ways in which market participants on the demand side can interact with the wholesale market. The first and second ways for DR to participate are part of the energy market design; the third relates to ancillary service (AS) markets; and the fourth relates to capacity markets.

The first avenue for demand side participation is price-responsive load: customers who react to prices by adjusting their demand, but without bidding into the wholesale market. As in any other market, electricity consumers tend to reduce their consumption if prices rise, all else equal. These consumers may be said to have provided DR in the sense that they purchase less electricity when prices are high than they would have done if prices had been lower.

Second, in some markets there are explicit mechanisms for individual consumers, or demand response aggregators (DRAs) acting on behalf of many consumers, to bid or offer[3] directly into the wholesale market and thus be dispatched by the system operator in the same way that generation is. This second route for DR to participate may be either: (a) a bid curve (price and quantity pairs) reflecting the customer's willingness to pay for energy, or (b) supply-side participation reflecting the minimum payment needed for the customer to curtail and supply back its energy, effectively participating in the market in a similar way to a generator.[4]

Third, system operators typically procure a number of different AS products from market participants. These AS products are required to ensure that the system is robust to outages and other unexpected changes in supply or demand. Depending on the nature of the AS product and the technical design, market participants on the demand side may be eligible to supply.

And fourth, some market designs include a mechanism for procuring capacity that is separate from the energy market. Generators and DR providers are paid to be available to generate or curtail load and avoid emergency events over and above revenues that they earn in the energy market.

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3 Conventionally, bids would refer to a bid to purchase electricity (i.e., load) and offers would refer to an offer to sell electricity (i.e., generators). As we explain below, in some markets DR "offers" a *reduction* in demand into the wholesale market and is therefore similar to generation.

4 DR participating on the supply side is sometimes termed "negawatts".

A. Demand Response in the Energy Market

Electricity customers, especially smaller customers, often pay retail prices that do not follow short-term movements in the wholesale price as it changes with supply, demand, and other fundamentals. Larger electricity consumers may pay prices that are linked to the wholesale price. The latter may therefore be able to respond to short-term price signals and adjust their consumption accordingly. This route for DR to participate in the energy market is sometimes referred to as price-responsive load because it does not depend on any specific wholesale mechanism or market design beyond the normal price mechanism. This impact of prices on the level of demand is not directly apparent to the system operator in the same way that it would be if consumers or retailers were bidding a "demand curve" into the wholesale market in the same way that generators offer a "supply curve." In these markets, the system operator dispatches generators to meet a forecast of demand but few (or sometimes no) loads are formally dispatched. The system operator's demand forecast may include an estimate of the extent to which load may respond to price.

In some jurisdictions, the market design allows customers to participate directly in the wholesale energy market by submitting a schedule of quantity and price bids for demand-side dispatch, similar to how generators submit quantity and price offers for supply-side dispatch. However, we observe very limited participation.

Some jurisdictions also provide specific mechanisms for DR to "sell back" energy as supply. Market participants on the demand side may be paid to reduce their consumption, with such payments being independent from and additional to any benefits derived by purchasing a reduced quantity of electricity. DR is paid to reduce consumption, and such payments are separate from the regular settlement process through which the consumer pays for energy consumed (either directly or through a retailer).

B. Demand Response in Capacity and Ancillary Services Markets

Some wholesale electricity market designs incorporate a mechanism to pay capacity resources to be available to provide energy. Other market designs, including Australia's National Electricity Market (NEM) are "energy only" and do not have explicit capacity mechanisms. Where there is a capacity mechanism, often both generators and demand-side resources are able to participate. In several of the markets we studied, this route for DR to participate in the wholesale market is very significant in terms of the total revenues available to DR. Although the NEM does not have a capacity mechanism, we have included capacity mechanisms in our study because this is often the dominant route for DR integration (often leading to energy market participation as a side-product) and because some design questions addressed in respect of capacity mechanisms may also be relevant for designing a mechanism for DR to participate in energy-only markets.

All wholesale electricity market designs incorporate mechanisms for the system operator to procure various kinds of AS. The system operator requires AS to manage generator outages, other unexpected changes in supply or demand, and to keep the system in balance in real time. In some markets the technical specification of (some) AS products permits DR to provide AS.

C. Our Study

In Australia's NEM there are no explicit mechanisms to require market participants on the demand side to participate in the wholesale energy market, although some can participate voluntarily. Large price-sensitive loads (greater than 30 MW) can opt to become "scheduled loads". Scheduled loads are required to submit price-quantity bids and to comply with dispatch orders. Since there are costs of complying with technical, bidding and dispatch requirements, most loads remain unscheduled. A notable exception is Snowy Hydro which has some pumps that are scheduled. Snowy Hydro recently put forward a Rule Change Request to make it compulsory for price sensitive large loads to bid into the electricity market.[5] We also understand that there is currently no route for DR to provide AS in Australia.

We understand that a Rule change proposal has been put forward that would permit loads, as well as demand response aggregators (DRAs), to participate in the NEM on the supply side. The Australian Energy Market Commission (AEMC) asked us to review how wholesale markets in a range of jurisdictions have been designed to facilitate DR participation.

We have studied the ways in which DR participates in electricity markets in six different jurisdictions. The aim of our study is to document how these jurisdictions have integrated DR into wholesale markets, including energy markets, markets for ancillary services, and markets for capacity. In some jurisdictions the market design has permitted demand-side participation for many years. We seek to identify any recent trends or lessons learned that may be relevant to ongoing work to improve the design of the NEM. Where there are ongoing debates over the optimal design of mechanisms to integrate DR, we have described the options under consideration. In section II we introduce the six markets we have studied, and provide an overview of the market design and the type and extent of DR participation. Section III describes the DR programs in the three energy-only markets and Section IV similarly elaborates on DR programs in the three markets with capacity mechanisms. Finally, in section V we draw out key observations across the six markets.

5 Whitby, Roger, Executive Officer, Trading (Snowy Hydro Ltd.) to John Pierce, Chairman (Australian Energy Market Commission), re Proposed rule change: Demand Side Obligations to Bid into Central Dispatch, June 10, 2015.

II. Overview of Markets Surveyed

A. Range of Market Designs and Regulatory Contexts Surveyed

Our review covers six electricity markets from three countries and two continents, spanning a range of political, legal, and regulatory contexts. Three of the markets (Singapore, Alberta, and ERCOT)[6] are "energy-only", in the sense that they do not provide long-term availability payments to generation (or demand resources) to secure sufficient capacity to meet future peak demand. In these markets generators (and potentially DR resources) earn revenues by selling energy and AS. The other three markets (PJM, ISO-NE, and Ontario)[7] include formal capacity obligations that incorporate some form of long-term availability payment. In these markets, generators and demand resources earn revenues by selling energy, AS and capacity.

The distinction between energy-only and capacity markets is important because in many cases DR receives greater payments from participating in capacity markets than from participating in the energy market alone. In electricity markets with formal capacity mechanisms, most of the revenue earned by DR providers comes through capacity payments rather than from participating in the energy market or by providing ancillary services (AS). Total payments to DR tend to be higher per MW in markets with a capacity mechanism. While the distinction between energy-only markets and capacity markets is important, in some energy-only markets there are "emergency" products that are similar in some regards to a capacity payment.

Table 1 shows a high level description of the overall market design of the six markets studied in this report, as well as the NEM, focusing on aspects of market design that are relevant to DR. The table highlights features of each market that affect DR's ability to participate and the revenues DR is able to earn. For example, as discussed above, the overall market design (energy-only vs. capacity) has a significant impact on the revenues available to DR. These features affect the quantity of DR that is likely to participate in each market. Note that the table does not address the question of how payments to DR should be calculated, or the standards that DR must meet in order to participate. As we will discuss later in the report, these questions are the subject of ongoing dispute in several markets.

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6 ERCOT is the organized wholesale market which covers much of Texas.

7 ISO-NE covers the New England region in the northeastern US (the states of Connecticut, Rhode Island, Massachusetts, New Hampshire, Vermont and Maine. PJM includes all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

Table 1
High-level Description of Markets Surveyed

	Australia	PJM	ISO-NE	Ontario	Singapore	Alberta	ERCOT
Market Model for Supporting Investment in Capacity	Energy-Only	Capacity Market	Capacity Market	Administrative Planning (now developing a Capacity Market)	Energy-Only	Energy-Only	Energy-Only (and a small emergency DR program)
Energy Market	Zonal Real-time	Nodal Real-time and day-ahead	Nodal Real-time and day-ahead	1 region with border pricing Real-time only (day-ahead scheduling but no market)	Nodal Real-time only	Single zone Real-time only	Nodal Real-time and day-ahead
Energy Market Price Cap	$13,800/MWh AUD	$2,700/MWh (AUD $3,660/MWh)	$4,050/MWh ($6,169/MWh AUD)	$2,000/MWh (CAD) ($2,088/MWh AUD)	$4,500/MWh ($4,463/MWh AUD)	$1,000/MWh (CAD) ($1,044/MWh AUD)	$9,000/MWh ($12,203/MWh AUD)
Ancillary Service Products (those where DR contributes significant quantities are shown in **bold**)	Regulating raise/lower, Fast raise/lower, Slow raise/lower, Delayed raise/lower	Regulation, **Synchronized scheduling reserves,** **Day-ahead scheduling reserves**	Regulation, 10-min spin, 10-min nonspin, 30-min nonspin	Regulation, 10-min spin, 10-min nonspin, 30-min nonspin	Regulation, Primary reserve, Secondary reserve, Contingency reserve	Regulation, **Contingency Reserves (Spinning Reserve, Supplemental Reserve),** **Intertie Contingency (LSSi)**	Regulation, **Responsive reserves service,** **Non-spinning reserves service**
Timing of Ancillary Service Procurements	Daily	Daily	Forward reserve market Day-ahead and real-time co-optimized	Long-term procurement market Real-time co-optimized offers	Daily	Operating reserves market clears day ahead, not co-optimized with energy	Daily
DR Aggregators	No	Yes	Yes	Yes	Yes	Not in energy Yes in some AS products	Not in energy Yes in Emergency Response Service

Sources and Notes:

Ancillary Service products that DR is currently allowed to participate in are indicated in bold.

Australia: Australian Energy Market Commission, "National Electricity Rules Version 72," July 2015. Posted at http://www.aemc.gov.au/energy-rules/national-electricity-rules/current-rules.

PJM: PJM, "PJM Manuals," July 2015. Posted at http://www.pjm.com/documents/manuals.aspx.

ISO-NE: ISO New England (2015), "Market Rule 1." July 2015. Posted at http://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf and http://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf

Ontario: IESO, "Overview of the IESO-Administered Markets," Jan. 2014

Singapore: EMA, "Implementing Demand Response In the National Electricity Market of Singapore: Final Determination Paper," Oct. 2013. Note that Singapore has an ancillary service DR program, but participation is only about 20 MW.

Alberta: AESO, "Guide to Understanding Alberta's Electricity Market," http://www.aeso.ca/29864.html. AESO, "Ancillary Services," http://www.aeso.ca/market/5093.html.

Texas: Electric Reliability Council of Texas, "Operating Procedures," 2015. Posted at http://www.ercot.com/mktrules/guides/procedures.

Several other energy market details can also affect DR earning potential, including whether the market incorporates zonal or nodal pricing, whether resources are scheduled and/or paid day-ahead or only in real time, the time interval for dispatch and settlement, and the cap on prices in the energy market.

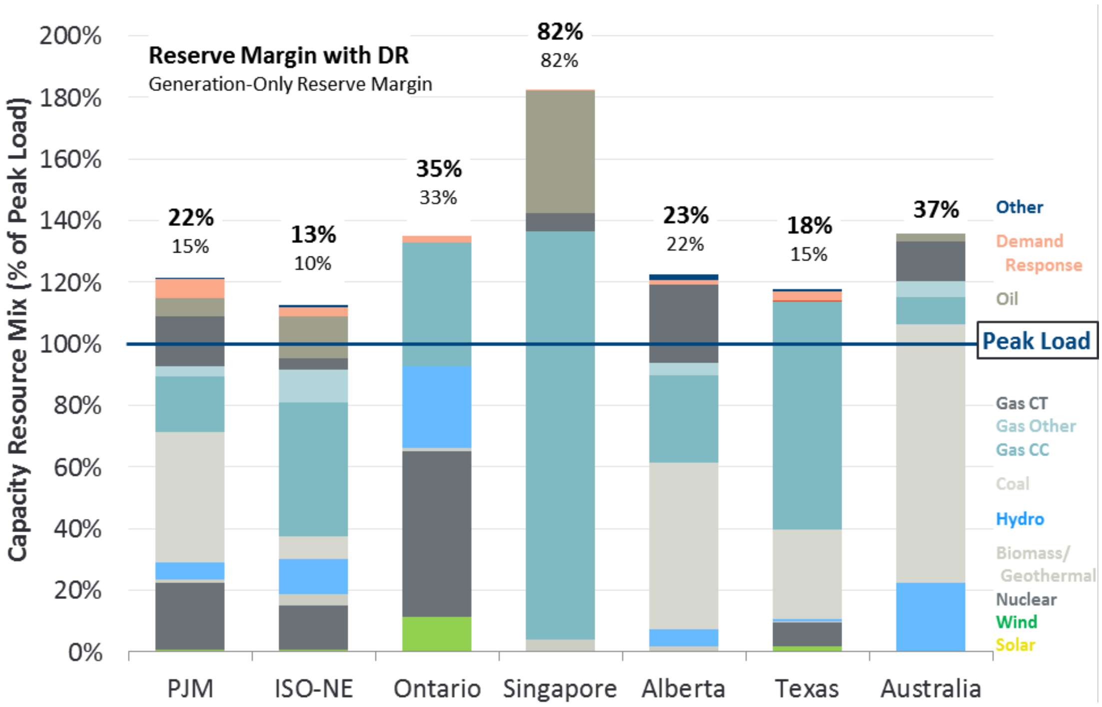
Whether the energy market incorporates a zonal or nodal structure can provide an incentive or disincentive for DR to bid. Most loads pay a zonal price even in a nodal structure, so in nodal markets, DR bidding price-sensitive demand into the market may be dispatched based on a nodal signal, but only avoid energy costs at the zonal level. This may be a disincentive for DR to participate in the market in this way because a DR provider faces a down-side risk of being dispatched based on a nodal price that exceeds its strike price, but only avoiding the (lower) zonal price during settlement. Note also that the effect of zonal vs. nodal pricing may differ depending on whether a given DR provider aggregates load reductions across several nodes.

Differences in the dispatch and settlement intervals can also provide an incentive or disincentive for DR to actively bid. We discuss an example of this in Section III.B.

The structure of AS markets is also an important influence on the degree of participation from DR, including the variety of products available, the timing of procurements, and whether and how DR is allowed to participate in the full range of AS products. Finally, different markets treat DRAs in different ways, with some offering the opportunity to participate directly in all aspects of the market, while others limit DRA participation to specific products.

Figure 1 shows installed capacity of various types of generation as well as DR capacity available in each of the six markets and Australia as a fraction of peak load. For each market, we report both the reserve margin with DR and the generation-only reserve margin. Note that in Figure 1 the amount of DR shown includes only DR capacity that would be available on peak. In PJM and ISO-NE, this DR is procured through the capacity markets. In ERCOT it is procured through an emergency DR program. In Alberta, it is paid through a different program design that results in an availability payment. The figure does not show DR that participates only in the energy or AS markets.

Figure 1
Capacity Resource Mix by Market



Sources and Notes:

Australia: Data aggregated by region from the Australian Energy Market Operator (AEMO), "Generation Information" downloaded in July, 2015. See http://www.aemo.com.au/Electricity/Planning/Related-Information/Generation-Information. Solar and wind capacity values de-rated using 45% and 9%, respectively, sourced from AEMO 2014 South Australian Electricity Report, pp. 19 and 27. Reported capacities are installed capacities (not de-rated for availability).

PJM : Data from Velocity Suite, ABB Inc. Wind & Solar de-rated using PJM capacity factors.. Demand Response provides Capacity or Ancillary Services. Peak load includes DR and Energy Efficiency. Reported generator capacities are ABB Inc. Net Summer Capacities.

ISO-NE: Data from ISO New England, "2015 CELT Report," Tables 1.3 and 2.1. See: http://www.iso-ne.com/static-assets/documents/2015/05/2015_celt_report.xls Reported generator capacities are ISO NE Summer Seasonal Claimed Capabilities.

Ontario: Data for 2013 from IESO's "Comparison of 2013 Long-Term Energy Plan to 2013 Actual Results" and "Ontario Reserve Margin Requirements." PV includes grid-connected and behind-the-meter capacity. Coal eliminated in Ontario as of April 2014. DR capacity includes OPA DR programs and Dispatchable Load. Reported generator capacities are capacities available at summer peak hour.

Singapore: Generation capacity data from Singapore Energy Statistics 2014. Biomass/Geothermal corresponds to "waste-to-energy" capacity from source. PV nameplate capacity de-rated using a factor of 45%. DR capacity includes interruptible loads providing primary, secondary, and contingency reserves based on 2014 EMC Price Information data. Reported peak load occurred in June 2014. Assumed reported load was reconstituted. Planning reserve target of 30% sourced from EMA website. Reported capacities are installed capacities (not de-rated for availability).

Alberta: Data from Velocity Suite, ABB Inc. The AESO includes no wind and 66% of hydro capacity in reserve requirements. Demand response capacity is based on the Demand Opportunity Service. 2014 peak load is not weather normalized. Generator capacities are ABB Inc. Net Winter Capacities.

Texas: Data from ERCOT Capacity, Demand and Reserves Report, May 2013 which aggregates gas types. http://www.ercot.com/content/news/presentations/2013/CapacityDemandandReserveReport-May2013.pdf Demand response is the sum of Responsive Reserve, Emergency Responsive Service, and the portions of Energy Efficiency Programs dispatched during emergencies. 2014 peak is not weather-normalized. Wind capacity values are de-rated using a factor of 8.7%.

Where possible, we report capacities as a percentage of the weather-normalized, reconstituted peak demand. Weather normalization attempts to correct for unseasonably severe weather that may have led to higher or lower than usual peaks. We do not perform this normalization ourselves, but we use weather-normalized values where they are reported by the relevant system operator. Where weather-normalized values are not reported, we use a non-normalized value and indicate this in the notes. Since we are counting DR as a source of peaking capacity, it is important to "add back" an estimate of DR curtailment to the measured peak demand. The resulting estimate is termed the "reconstituted" peak demand. We show reported reconstituted peak demand where this is available.

Singapore stands out with its very large reserve margin. From 2005 to 2014, licensed generation capacity increased by over 4 GW to more than 12 GW while peak load grew by just over 1 GW to 6.8 GW.[8] The majority of this new capacity came from simple and combined cycle gas turbines, which have almost entirely replaced oil as a source of supply.

Generation-only reserve margins differs most substantially from reserve margins including DR in PJM, with a 7% difference based on 2014 registered DR data. Note that the amount of DR that cleared the forward capacity market for delivery in 2014 was larger than the registered amount that actually materialized (we discuss the reasons for this below). The quantity of capacity-related DR in MW terms in PJM is also substantially higher than in other markets. This observation is consistent with the fact that PJM procures DR by allowing it to compete with generation to provide on-peak capacity as part of the capacity market design.

The fact that Ontario, despite being a capacity-planning jurisdiction, does not have a substantial difference between its reserve margin with and without DR may result from the fact that DR and generation do not directly compete to provide capacity resources as they do in other markets. In Ontario, separate mechanisms with separate quantity targets are used to procure capacity from DR and from generation. The Ontario Power Authority (now merged with the Independent Electricity System Operator) sets targets for DR and then procures capacity via its DR contract programs. Under this arrangement, the total quantity of peaking DR depends mostly on how high the targets are.

ERCOT has a very small difference between its reserve margin with and without DR.[9] Much like Ontario, ERCOT procures emergency DR through contracts, procuring capacity up to a maximum expenditure limit. The quantity procured is a function of the expenditure limit.

The size and frequency of energy price spikes drive the potential revenues of DR in the energy markets. The size of the largest spike provides an estimate of the maximum revenue (or avoided cost) a DR provider could earn from one curtailment. The frequency of price spikes determines the size of the energy market opportunity for DR on an annual basis. Figure 2 shows weekly average real-time energy prices for the energy-only markets and the capacity markets, illustrating the differences in energy price volatility across markets. We have chosen to show weekly average, rather than hourly, values in order to avoid visual

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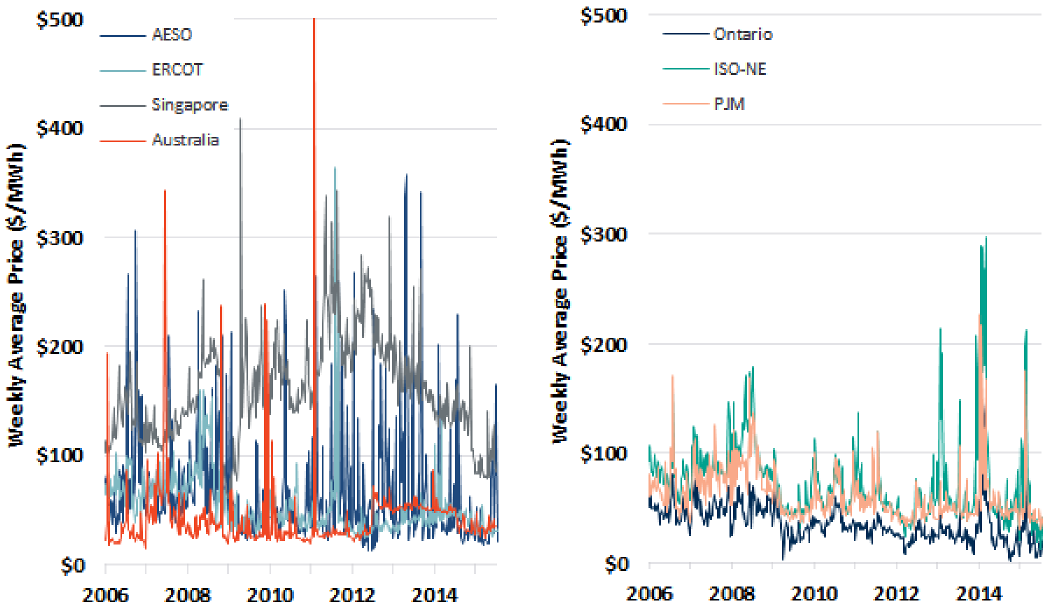
[8] Energy Market Authority (EMA), *Singapore Energy Statistics 2014: Energising Our Nation*, October 2014.

[9] Note that we are reporting ERCOT's Emergency Response Service and TDSP programs in the figure. There may be substantially more load that responds to peak conditions without being controlled by the system operator.

clutter. The figure shows that prices are substantially more variable over time in the energy-only markets.

Figure 2
Weekly-average Energy Prices in Energy-Only Markets (Left) and Capacity Markets (Right)



Sources and Notes:
Values converted to AUD from local currency with 7/17/2015 exchange rates.
Australia: Australian Energy Market Operator (Values for New South Wales region)
Other markets' price data from ABB Inc. (2015). Note that the US and Singapore dollars have appreciated relative to the Australian dollar over the last five years.

Table 2 shows a measure of price volatility for each of the markets. It reports the standard deviation of the first differences in hourly prices from 2006 through 2014, converted into Australian dollars. This measure captures the variability of prices around their long-term trend. Price volatility for the three capacity markets ranges from $22/MWh to $29/MWh. For the four energy-only markets, volatility ranges from $56/MWh to $146/MWh.

Table 2
Price Volatility Across Markets (2006-2014)

	IESO	ISO-NE	PJM	AESO	ERCOT	NEMS	NEM
Standard Deviation of First Differences $AUD/MWh	$22	$28	$29	$80	$83	$56	$146

In markets with higher short-term price volatility, DR has more opportunity to create and capture value by participating in the energy markets. While electricity consumers may be able to adapt to longer-term changes in price, short term variation can leave these consumers without any means of responding. By increasing the effective elasticity of overall demand, energy market DR can reduce this price volatility. Given an appropriate market design, DR providers can also capture some of this value for themselves.

B. Range of Demand Response Products and Penetration Levels Surveyed

The markets reviewed in this report incorporate a large number of DR products and have achieved varying levels of DR penetration. In Table 3, we report the DR programs in each market, categorized in terms of whether they provide Capacity or Emergency service, Ancillary Service, or Energy service. Note that, while DR is allowed to provide regulation in Texas and PJM, participation is insignificant. Also note that participation in dispatchable Energy Market programs (those reported in the Energy Market row of Table 3) is very low in some markets. See Figure 3 for more information on participation.

Table 3
Demand Response Programs

	PJM	ISO-NE	Ontario	Singapore	Alberta	Texas
Capacity or Emergency Products	Emergency Load Response Program (procured via capacity market)	Forward Capacity Market DR	Transitional Demand Response Program Dispatchable Load	None	Demand Opportunity Service	Emergency Response Service
Ancillary Service Products	Economic Load Response (Synchronized Reserves and Regulation)	None	Dispatchable Load	Interruptible Load Program	Spinning and Supplemental Reserves LSSi	Responsive Reserves (mostly uncontrollable load resources; small amounts of controllable load resources), Non-Spinning Reserves, Regulation
Energy Market (other than demand reacting to prices)	Economic Load Response (Energy)	Real-Time Price Response, Transitional Price-Responsive Demand	Dispatchable Load DR Pilot Program	Demand Response Program (proposed)	Demand side bidding	Controllable Load Resource or Aggregate Load Resource (Energy Only)

Notes:

PJM: PJM calls their energy and ancillary service market DR programs "Economic Load Response". Emergency Load Response can provide capacity and energy, or energy only. Economic Load Response has energy, day-ahead scheduling reserves, and synchronized reserves components.

ISO-NE: ISO-NE's "Real-Time Price Response" and "Transitional Price-Responsive Demand" programs are dispatchable energy market DR programs. Two DR programs exist for "Active" (i.e., dispatchable) resources, Real-Time Demand Response (RTDR) and Real-Time Emergency Generation (RTEG). These programs are described in greater detail in Section IV.B.1 and IV.B.2.

Ontario: Transitional Demand Response Program is an IESO-administered successor to OPA's DR3 contracted capacity program. Participants receive an availability payment and a curtailment payment. DR Pilot program participants can provide 5-minute load following, hourly load following, and unit commitment. Dispatchable loads can provide energy and operating reserves. Ontario also has some load that responds to priced but is not dispatchable.

Singapore: Interruptible loads can provide contingency reserves. The Demand Response Program is scheduled to begin in 2015.

Alberta: Load is allowed to bid into the energy market and be dispatched (Demand side bidding), but there is no participation. Substantial load responds to wholesale prices without being dispatchable. Loads can provide supplemental (i.e. non-spinning) reserves and a new program will allow provision of spinning reserves. The Load Shed Service for Imports (LSSi) is an under-frequency paid interruptible load service to support the intertie with British Columbia.

ERCOT: Controllable Load Resources can provide responsive reserve, non-spinning reserve, regulation, and energy (but participation is low). Uncontrollable Load Resources provide reserves primarily via under-frequency relays.

We can characterize the three types of DR programs shown in Table 3 as follows.

- **Capacity or Emergency Products**
  These products are intended to meet traditional planning reserve requirements (or targets) that support reliability during super-peak load conditions. They do so by providing system operators with the ability to reduce demand when needed. In jurisdictions with resource adequacy requirements, DR is generally procured through the capacity market. Some energy-only markets also procure emergency DR through special programs. DR providing capacity or emergency products generally receives an availability payment over a long time horizon and may or may not receive an additional payment for curtailments actually called.

- **Ancillary Service Products**
  These products are intended to help balance supply and demand at short time scales, including following a contingency. Although providers generally receive an availability payment, ancillary service products are usually procured with less lead time than capacity or emergency products. Ancillary service markets vary substantially across regions, but often include a "regulation" product requiring short time-scale adjustments to load within a real-time dispatch interval, one or more "spinning" reserve products requiring curtailment at short notice (seconds to 10 minutes) during a contingency, and "non-spinning" reserve products requiring curtailment with a longer lead time (30 minutes). In the event of a contingency, fast-responding products will activate first, helping to support system frequency. As products with longer lead-time activate, they help restore the system to its original state.

- **Energy Market**
  DR providers receive a payment, or avoid a payment they would otherwise make, on the energy market. In several US markets, DR participates on the supply side of energy markets, receiving payments similar to those of a generator. In other jurisdictions, DR behaves like a load, curtailing when prices are high. Some DR submits energy market offers or bids, similar to those submitted by generators, and is scheduled by the system operator, while some responds to price signals without system operator control.

Figure 3 shows the estimates of the quantities of DR procured in each market. We report quantities of DR by type—Capacity or Emergency, Energy, or Ancillary Services. Due to the fact that some DR providers are able to provide multiple services, we do not report a total value since there would be a risk of double-counting.

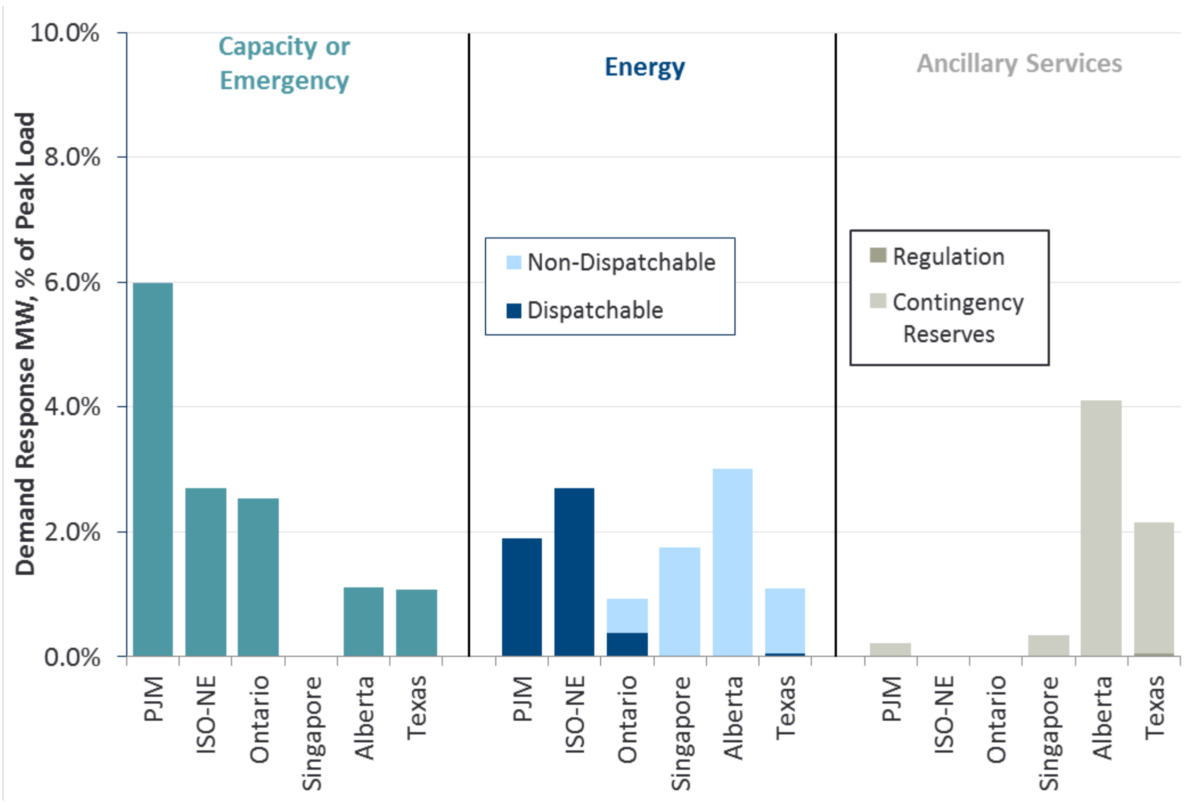
Figure 3 again shows a distinction between energy-only and capacity markets. The three capacity markets have substantially larger shares of capacity or emergency DR compared to energy market DR. PJM and ISO-NE may have larger shares than Ontario due to the fact that Ontario procures enough DR capacity to hit a DR-specific policy target, whereas PJM and ISO-NE allow DR to compete with generation to meet on-peak capacity targets.

Figure 3 also shows a distinction between the three markets where much of energy market DR is dispatchable—PJM, ISO-NE, and Ontario—and those where it is primarily non-dispatchable. In PJM and ISO-NE, loads participate in the energy market on the supply side and are paid the full wholesale energy price for curtailments. As we discuss in below, this payment is more than the cost that would be avoided if the load were paying the wholesale price and simply reducing consumption. The additional payment to DR receiving the full energy price acts as an incentive for DR to offer into the energy market rather than participate in a non-dispatchable manner as price-responsive load. In Singapore (until the new Demand Response Program begins operating), Alberta, and ERCOT, DR does not receive an incentive for offering into the market and being dispatched by the system operator. In Ontario, dispatchable loads do not receive an explicit incentive to become dispatchable, but they are made whole if dispatched in response to a forecast price and the real time price turns out lower and does not exceed their strike price.

AS programs vary substantially in magnitude across markets. Alberta's Load Shed Service for Imports (LSSi) program provides considerable capacity to support the Province's intertie with British Columbia. This program has a number of unique features which we discuss later in the report. While the program serves a purpose unique to Alberta (Alberta is particularly vulnerable to the loss of the intertie as it would then be electrically isolated from the rest of the interconnection), its payment structure could potentially be used in other markets to compensate loads providing operating reserves.

We comment further on Figure 3 in section V below.

Figure 3
Demand Response Penetration by Market



Sources and Notes:

PJM : All data from PJM's "2014 Demand Response Operations Markets Activity Report." Capacity bar includes Energy-Only component of Emergency Load Response Program as it involves a voluntary curtailment during emergencies. We were unable to find evidence of price-responsive loads.

ISO-NE: Peak load data from ISO New England's website, "Summer 2014 Weather Normal Peak Load," accessed June, 2015. See http://www.iso-ne.com/static-assets/documents/2014/10/summer_peak_normal_2014.pdf. DR data from ISO-NE Internal Market Monitor Report, "2014 Annual Markets Report," May 2015, pp. 93 and 95. See http://www.iso-ne.com/static-assets/documents/2015/05/2014-amr.pdf

Ontario: Data from IESO's "Comparison of 2013 Long-Term Energy Plan to 2013 Actual Results." Capacity bar includes both OPA/IESO DR program MWs and Dispatchable Load MWs. There was an inconsistency between DR reported in the Installed capacity table and the Demand Management table: we used the latter. Energy bar includes both Dispatchable Load and estimated effect of Time of Use Pricing (Non-Dispatchable). We were unable to find reported DR capacities in Ontario's AS markets though participation is allowed.

Singapore: Data from EMC's "Price Information – Capacity for Registered Facilities." Singapore does not currently have any Capacity/Emergency or Energy DR. AS quantity provides primary, secondary, and contingency reserves.

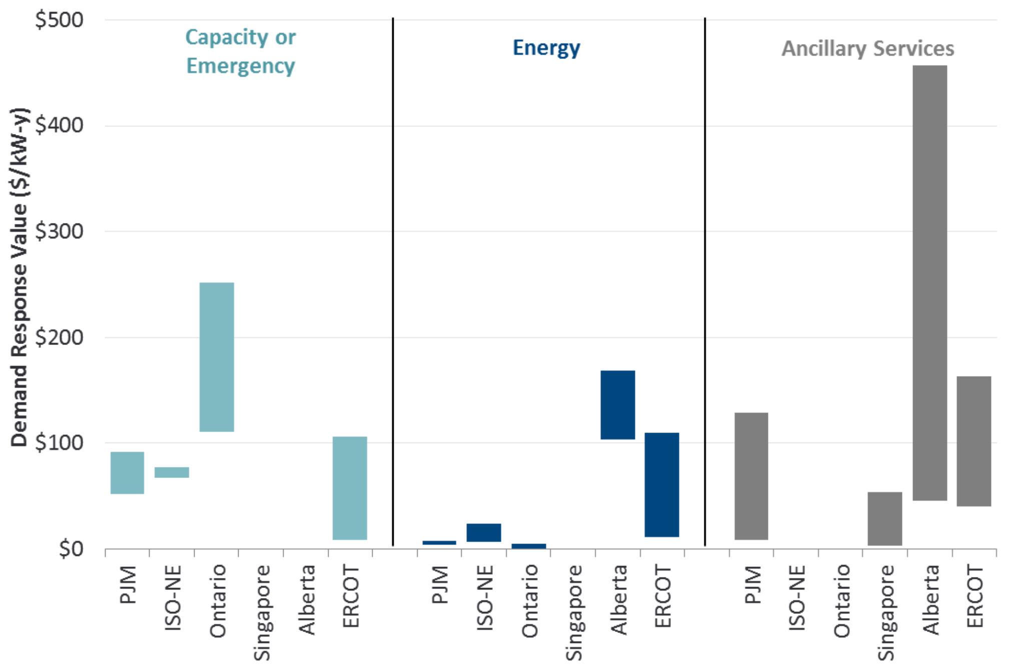
Alberta: Demand Opportunity Service (DOS) is counted as an emergency service as curtailment is only required in shortfall events. Price-responsive load is classified as energy demand response, and loads that participate in supplemental (SUP) and LSSi are included as ancillary services. Note that some loads are price responsive and participate in ancillary services. If participating in both, the load is counted as an ancillary service. Source: AESO 2011 Annual Market Statistics (http://www.aeso.ca/downloads/AESO_2011_Market_Stats.pdf). There have been minimal changes in participation levels of DR since that date.

Texas: Emergency Demand Response is the sum of Emergency Responsive Service, and the portions of Transmission and Distribution Service Provider Load Management Programs dispatched during emergencies. Dispatchable Energy includes 30MW of load that were in the process of being qualified to bid in the Real-time market in August 2014. Non-Dispatchable energy is the MW response to high wholesale prices. Loads providing Responsive Reserve are set equal to the maximum procured capacity. AS includes 36 MW of Controllable Load Resources qualified to provide regulation in 2014.

C. Value of Demand Response Products

Figure 4 shows an estimate of the value (revenues earned and/or avoided payments) that DR could realise, in $/kW-y AUD, from participating in Capacity or Emergency, Energy, or Ancillary Services in each of the markets. Ranges in the figure represent a number of sources of variation, including inter-year variation in capacity, energy, and ancillary service prices. Note that values in Figure 4 for PJM, ISO NE, and ERCOT are based on 2011-2014 data, Singapore is based on 2014 data, Alberta is based on 2013 data, and Ontario is based on 2009-2012 data.

Figure 4
Historical Demand Response Value by Product Type



Sources and Notes

PJM: Capacity values represent minimum and maximum capacity market clearing prices over last five years. Energy values represent total energy market DR payments divided by capable MW, minimum and maximum values 2011-2014. Ancillary services range represents minimum revenue for synchronized reserve market from 2011-2014 to maximum value for regulation market from 2011-2014.

ISO-NE: Capacity values represent minimum and maximum capacity market clearing prices over last five years. Energy values represent total energy market DR payments divided by capable MW, min and max values 2011-2014. Total Capacity and Energy payments converted to $/kW-yr rate by dividing by DR capacity in each year. Ranges represent maximum and minimum payments received from 2011 to 2014. Data from Annual Markets Reports of the given year.

Ontario: Capacity revenues based on OPA-reported contract costs for legacy DR2, DR3, and peaksaverPLUS programs. Energy market revenues based on energy margin calculation with an AUD $300/MWh strike price (see Figure 5).

Singapore: Market does not have a capacity or emergency product or an energy product currently. Ancillary Service values represent earnings of DR providing 8760 hours of reserves at 2014 prices assuming they provide primary reserves in the lowest quality group (group E) at the low end and contingency reserves in the highest quality group (group A) at the high end. Data from emcsg.com/marketdata/priceinformation.

Alberta: We do not report revenues for emergency DR in Alberta due to the idiosyncratic nature of the DOS program. Energy revenues are the annual avoided costs that existing price-responsive loads realize converted to $/kW-yr (based on AESO provided data). The Ancillary Service revenue range is capped on each end by the hypothetical revenue earned from providing supplemental reserves in all hours of 2013 (upper end), and by the hypothetical revenue received by $5/MW availability payment for providing LSSi in all hours of 2013 (lower end).

Texas: Emergency Revenues are capped at ERS payments assuming participation in all four periods, and have a floor that assumes participation in only one of the periods. In Ancillary Services revenue calculations, the price is converted from $/MWh to $/kW-yr using a demand factor of Average/Maximum RRS MW awarded.

As we observed previously in Figure 3, markets with capacity or emergency products tend to secure more DR due to the magnitude of payments for these products. Ancillary service payments can also be substantial, with energy market payments usually being fairly small. In markets with capacity or emergency DR, resources can generally receive both a capacity/emergency availability payment and be eligible to participate in energy markets. However, an individual provider may not always be able to capture both energy and AS value. Market operators often allow providers to offer into both energy and AS markets, but will only clear each MW in one market or the other. However, given that DR generally has relatively high strike prices, its energy market revenues are likely to be earned mostly in a small number of hours. Clearing the energy market in these hours may not substantially reduce the potential to receive AS payments.

We comment further on Figure 4 in section V below.

Figure 5 shows the value captured by curtailing a load with a strike price of AUD $300/MWh in response to high real time electricity prices.

Figure 5
Value of Operating as Demand Response in the Energy Market

Sources and Notes:
Australia: Australian Energy Market Operator. Values for the New South Wales region only.
PJM, ISO-NE, Ontario, Texas : Velocity Suite, ABB Inc.
Singapore: Energy Market Company Pte Ltd. Alberta: Velocity Suite, ABB Inc.

Figure 5 reports the sum of revenues per kW (energy price minus strike price) for each hour of curtailment over the course of each year (or, in other words, it shows the difference between the total energy bill assuming consumption in every hour of the year, irrespective of the price, and the bill assuming that the load curtails in any hour where the price is greater than $300/MWh). The figure shows that the value of this energy market participation varies substantially across markets, and also from year to year within markets—particularly in energy-only markets. With some exceptions, this chart is consistent with the idea that DR's energy market value tends to be higher in energy-only markets.

While the value of DR tends to be higher in energy-only markets, it is also somewhat more variable than it is in capacity markets. Figure 5 shows substantial variation in value for the energy markets, particularly in Australia and AESO, from 2006 through 2014. In 2013, value in ISO-NE (a capacity market) exceeded that of ERCOT and Australia (energy-only markets). In 2014, value in both ISO-NE and PJM exceeded that in Singapore, ERCOT, and Australia while value in IESO exceeded that of Australia. While part of this reversal may be attributed to higher prices in ISO-NE and PJM in 2013 and 2014[10], it also serves as a further illustration of the uncertainty in the energy market value of DR in energy-only markets.

While Figure 5 shows the potential value of DR operating in the energy market, the ability of DR providers to capture this value also has an effect on the ultimate penetration of DR achieved. Issues such as the duration and predictability of DR events, enabling infrastructure, retail market structure, and active participation of aggregators can influence the ability of DR to capture potential energy market value.

10 High prices in ISO-NE and PJM in 2013-2014 are consistent with natural gas supply constraints in the winter months of those years.

III. Energy-Only Markets

A. Singapore

Singapore's wholesale electricity market deregulation process began in 1998 with the creation of a day-ahead wholesale market known as the Singapore Electricity Pool. In 2001, the government decided to encourage further electricity market reforms and created the Energy Market Authority (EMA) to preside over the creation of a retail electricity market. The National Electricity Market of Singapore (NEMS), encompassing real-time wholesale and retail electricity markets, began operating in 2003 with the EMA as its regulator.[11] In addition to energy, the NEMS also procures ancillary services in the form of primary, secondary, and contingency reserves, and regulation.[12] The energy market has a 30 minute dispatch period and settlement interval.[13] Demand response in the NEMS currently consists of the Interruptible Load ancillary services program. A new energy market Demand Response program is due to begin in 2015. The EMA prepared a public consultation paper on their program design in 2012 and finalized the program in 2013. While the program has not yet begun and a few implementation details are not clear, most aspects of the program's design have been laid out in the Final Determination document and we focus on this design here.

1. Timeline and Status of Demand Response Developments

Demand response has formally been a part of the NEMS since 2004, when the Interruptible Load (IL) scheme was introduced. The program allows loads to provide primary, secondary, and contingency reserve. Participants in the IL program are compensated at the relevant reserve price (the same price paid to generation for providing primary, secondary, and contingency reserves) for their availability and are not paid for either activation or energy.[14] The system operator imposes limits on the amount of reserves provided by loads (20% for primary, 20% for secondary, and 30% for contingency). It also requires that loads be equipped with "Monitoring-Recording-Activation" devices incorporating an under-frequency relay (for provision of primary and secondary reserves), monitoring, and control equipment. Load facilities are subject to initial and ongoing capability tests, as well as reduced payment based on historic failure to fully comply with dispatch signals.

In 2012, the EMA issued a consultation paper, seeking stakeholder comment on a proposed Demand Response Mechanism (DRM) to enable load to participate actively in the wholesale energy market by allowing demand side bidding. The DRM envisioned a market design in

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11 EMA, *Introduction to the National Electricity Market of Singapore*, Version 6, Updated as of October 2010, available at https://www.ema.gov.sg/cmsmedia/Handbook/NEMS_111010.pdf.

12 Energy Market Company (EMC), "Monthly Trading Report June 2015," prepared for the National Electricity Market of Singapore (NEMS), https://www.emcsg.com/f1370,101781/Public_Monthly_Trading_Report_-_Jun_2015.pdf.

13 EMA, *Singapore Electricity Market Rules: Chapter 8 Definitions*, July 1, 2015, available at https://www.emcsg.com/f283,7937/Chapter_8_Definitions_1Jul15_clean_.pdf.

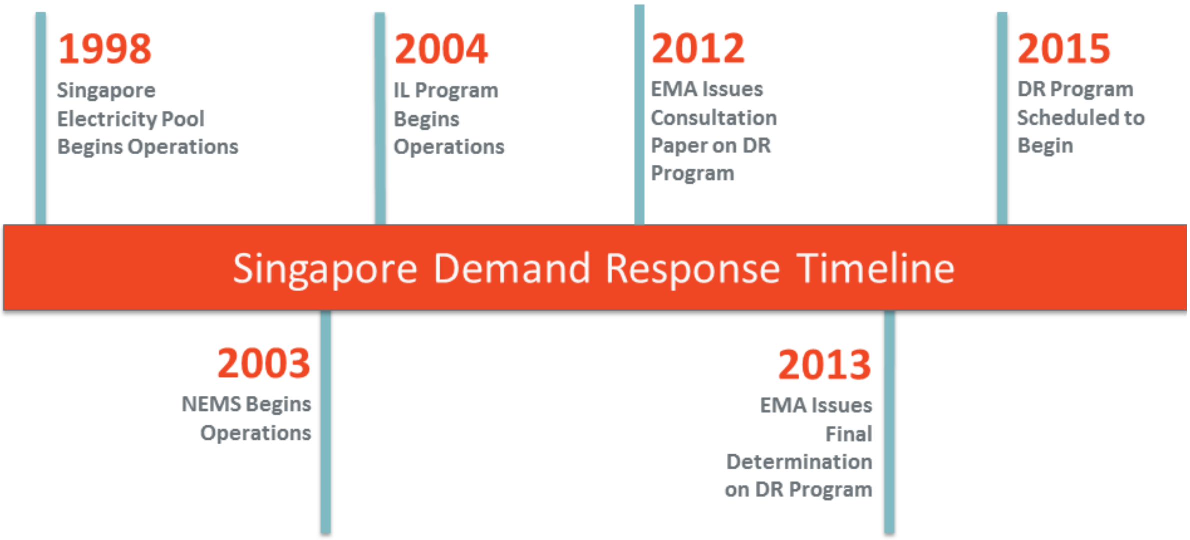
14 EMC, *A Guide to Providing Interruptible Load in Singapore's Wholesale Electricity Market*, available at https://www.emcsg.com/f146,16653/Guide_to_providing_IL_website_21082012.pdf.

which both retailers and independent DRAs would be able to actively participate. The program involves DR bidding into the energy market and following a dispatch signal from the system operator if their bid clears—with penalties for non-compliance. The bidding arrangements are discussed in detail below, but effectively the DR resource is required to bid a quantity it will consume if it is not "dispatched," and an incentive payment and corresponding load reduction that it will provide if it is dispatched (thereby avoiding the need for an administratively-determined "baseline"). The program provides an incentive payment to encourage participation by large loads and aggregators and also keeps retailers "whole" because they will be settled on the basis of metered load. Incentive payments to DR providers will be provided from an uplift charge applied to all load and charged to retailers.

In its 2012 consultation paper, the EMA had proposed to require DR to comply with dispatch signal within 10 minutes. In response to input received during its public consultation process, the EMA revised its original proposal to allow DR to include a ramp rate in its bid. This ramp rate would be used by the market clearing engine in a similar way to generator ramp rates. Compliance for a DR provider would be based on deviations from its dispatch signal, which would be constrained by the provider's ramp rate bid.

Retailers were provided with a "one-time" option to opt-out of the program altogether. Retailers that opted out would not have been able to participate subsequently, and would not be required to pay the uplift. However, retailers that opted out would not pay the regular system price: they would pay a higher system price estimated for the counterfactual scenario where DR did not participate in the market. In the event, no retailers opted out.

Figure 6
History of Demand Response in Singapore



2. DR Incentive Payments based on Wholesale Price Reductions

While some of Singapore's load is known to act as price-responsive load,[15] at present loads are not allowed to bid into the wholesale spot market and be dispatched by the system operator. After completing the consultation process described above, the EMA issued a Final Determination Paper on implementing DR in the NEMS. The implementation process includes a set of changes to market rules that would allow demand-side bidding in the wholesale market and create a new class of license for DR aggregators. Note that the program will not require all loads to bid. The changes would also create an incentive payment for DR providers. [16]

The incentive payment to the DR provider is related to the reduction in energy prices associated with demand side participation. According to the EMA, the payment will provide "an appropriate level of incentives for consumers to participate in the demand response program".[17] Calculating the size of the incentive payment involves running the system's Market Clearing Engine twice for each settlement interval where demand response clears: once including DR and once excluding it. As Figure 7 illustrates for a hypothetical scenario, DR tends to reduce the market clearing price. This price reduction is multiplied by the portion of load served to contestable consumers[18] to calculate a consumer surplus increase associated with DR. Contestable consumers are the segment of electricity customers who are eligible to switch to a competitive retail provider.

Under the EMA's proposal, DR providers would be paid 1/3 of the additional consumer surplus in aggregate. The Final Determination paper argues that the factor of 1/3 "will ensure that [the] majority of the benefits accrue to the rest of the consumer base … while providing a fair return to licensed load providers for the services they provide in the market".[19] This incentive payment would be allocated among DR providers proportional to their energy curtailment during the period of DR activation. The payment will be collected from an uplift charge on all retailers. As a result, during periods when DR is called, all retailers pay a lower price than they would have done in the absence of DR; those retailers whose customers are called to provide DR are also settled on a lower volume of energy than they would have done otherwise; and the DR providers in addition receive an incentive payment.

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15 Kay, Dallon (Diamond Energy), "Demand Response in Electricity Markets," presented at the EMC Singapore Electricity Roundtable 2011, Suntec Singapore, November 1, 2011, available at https://www.emcsg.com/f999,65667/Dallon_Kay__Diamond_Energy_.pdf.

16 EMA, *Implementing Demand Response in the National Electricity Market of Singapore*, Final Determination Paper," October 28, 2013, available at https://www.ema.gov.sg/cmsmedia/Electricity/Demand_Response/Final_Determination_Demand_Response_28_Oct_2013_Final.pdf

17 *Ibid.*

18 Essentially, all non-household customers, accounting for about 70% of total consumption.

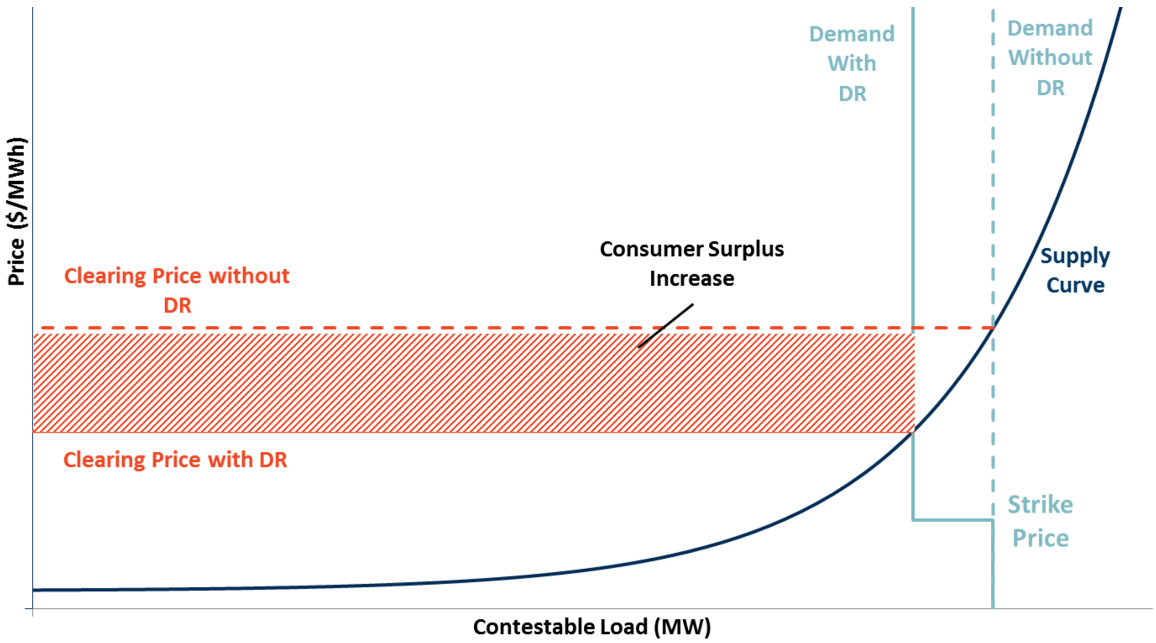
19 EMA, "Implementing Demand Response in the National Electricity Market of Singapore: Final Determination Paper," *Energy Market Authority*, 2013, p.15.

It is interesting to note that retailers were given a one-time option to opt out of the DR program entirely. Opt-out retailers would not have to pay the uplift charge to fund the DR incentive payments, but would also pay the higher system price calculated without including DR resources. In the event, no retailers exercised this option and so, once the program starts, all retailers will be required to pay the uplift (and will be eligible to act as DRA and receive the incentive).

Under a scenario where the market is at the price cap of S$4,500/MWh both with DR and in the absence of DR, the market operator would still provide an incentive payment. Under this scenario, the price change used in the calculation of additional consumer surplus would be the difference between the Value of Lost Load of S$5,000/MWh and the market price cap.

Figure 7 illustrates the effect of DR on demand, clearing price, and consumer surplus. The red shaded area represents the increase in consumer surplus (for contestable consumers only) associated with DR participation in the energy market, calculated by the market clearing engine. Under the proposed DR program, 1/3 of the consumer surplus increase shown in the figure would be paid to the providers of DR.

Figure 7
Singapore Demand Response Mechanism Incentive Illustration



3. Demand-Side Bidding Instead of Administrative Baseline

Measurement of the size of load curtailed by DR requires comparison of metered load with a baseline. In many jurisdictions, an administrative process sets this baseline, often by using historical load data to determine a facility's energy use under operating conditions similar to those during the curtailed period. Administrative baselines are often designed to be easily calculated using a transparent and relatively simple algorithm (though identifying a baseline that accurately reflects consumption absent DR can be a challenging process). However, they suffer from the possibility of gaming.

As the Final Determination Paper discusses, by understanding the administrative algorithm for determining the baseline, loads may be able to raise their baseline energy use and thereby receive additional incentive payments without changing their behaviour once called to provide DR.[20] Singapore's DR program will avoid administrative baselines, instead soliciting the DR provider for the baseline through a bidding process—and penalizing the provider if the customer in fact uses less than the baseline when not called.

A demand side bid under the DR program will include:

- the quantity of demand with no DR incentive payment (i.e., the quantity that will be taken if the resource is not dispatched and the load pays the regular system price);
- a strike price or incentive payment, which will be paid to the DR provider if it is dispatched; and
- the corresponding demand reduction that occurs at the strike price.

If a DR bid clears, the system operator will simply subtract the metered energy from the level that was bid at a price of $0/MWh to determine the volume of DR supplied. Under the proposed program bids submitted by DR providers are binding. If the market clears below the strike price, the DR provider is subject to a penalty if its load falls below 95% of its baseline bid. If the market clears above the strike price, the provider is subject to a penalty if its load *reduction* falls below 95% of the reduction in its bid. If the provider provides less than 100% but more than 95% of the reduction in its bid, it is not penalized, but also does not receive the incentive payment. The provider only receives the incentive payment if it curtails 100% or more of the bid amount (though if the provider curtails more than 100%, it only receives the incentive payment based on its scheduled curtailment). The system operator accounts for the ramp rate of the demand side resource in issuing dispatch signals and in determining compliance.

The market design includes a further feature to prevent gaming—a strike price floor whose level moves with the price of natural gas.[21] The EMA is concerned that a DR provider could submit a bid with a very low strike price during a period when it intended to reduce consumption even in the absence of an incentive payment. By making a presumably low-risk gamble that the market clearing price exceeds this very low strike price, the DR provider would be eligible for an incentive payment for a demand reduction it was already intending to make. A price floor makes this kind of gamble much riskier.

Note that an important feature of the EMA proposals is that the retailer—as distinct from the DR provider (load or DRA)—is not involved in the process. The retailer does not have to make a binding bid on behalf of its customers, does not receive an incentive payment, and will not be penalised for non-delivery.

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[20] *Ibid.*

[21] The floor price is equal to 50% above the officially-estimated cost of a new entrant generator, termed the "balance vesting price".

B. ALBERTA

Alberta initiated market restructuring in 1996 with the separation of transmission and distribution utilities from generators. The Power Pool of Alberta was created to facilitate the competitive wholesale market and dispatch in real-time. Full deregulation was in place by 2001 with the introduction of retail competition. The Alberta Electric System Operator (AESO) was formed in 2003 to take on the role of transmission planning and the market operations of the Power Pool.[22]

The AESO operates a real-time energy-only market with a price cap of $1,000 CAD ($1,044 AUD) and a price floor of $0/MWh.[23] Generator offers and load bids are accepted by the Energy Trading System (ETS), though at this time only generators offer on a regular basis and loads do not bid.[24] Generators are obligated to offer their full capacity into the market under must offer, must comply rules, unless there is an acceptable operational reason for the unit to be on outage or de-rated, but loads are not required to bid.

Offers (and bids) submitted to ETS may be changed up to two hours prior to the start of the settlement interval. The AESO dispatches generator offers as necessary in real-time based on changes to supply and demand, and the system marginal price is set every minute. The pool price is the hourly average of the system marginal price and is used for market settlement. Both loads and generators are settled against the hourly pool price.

Alberta has a significant percentage of industrial loads,[25] many of which respond in real-time to price signals though do not submit bids into the market. Demand response also provides AS and curtailable load in supply shortfall (emergency) events.

1. Timeline and Status of Demand Response Developments

Alberta's wholesale market allows demand side resources the opportunity to bid into the market. This capability is not used by loads at this time.[26] Demand side resources are eligible

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22 Alberta Electric System Operator (AESO), Guide to Understanding Alberta's Electricity Market, http://www.aeso.ca/29864.html (accessed 2015).

23 Note that generator offers are limited to $999.99/MWh (AESO Rule 203.1.3.3.a.i) and the price is set at the cap only during firm load shed (AESO Rule 201.6.3.1.b)
AESO, Current ISO Rules, in effect April 1, 2015, and Sections 201.6 Pricing (http://www.aeso.ca/downloads/Section_201-6_Pricing_(July_2_2014).pdf) and 203.1 Offers and Bids for Energy, (http://www.aeso.ca/downloads/Section_203.1_-_Offers_and_Bids_for_Energy.pdf) online at http://www.aeso.ca/rulesprocedures/18592.html (accessed 2015).

24 AESO, "AESO Demand Response Discussion Paper, Stakeholder Comment Matrix," December 17, 2009, p. 2, available at http://www.aeso.ca/downloads/DR_Comment_Response_Matrix_-_December_17_2009_.pdf.

25 In 2013 industrial load accounted for 51 percent grid-supplied electricity (this figure therefore excludes industrial load supplied from on-site generation). Province of Alberta, "Electricity Statistics," 2013, http://www.energy.alberta.ca/electricity/682.asp#customer.

to provide some ancillary services including supplemental (non-spinning) operating reserves and have been actively participating in that market since the creation of the AESO.

In 2005 the Alberta Government issued its Electricity Policy Framework in which demand response was one of many policy topics. The policy framework highlighted that demand response improves the efficiency of the market, and that Alberta's demand response from industrial customers (acting as price-responsive load) is notable in comparison with other jurisdictions.[27] In developing the framework, the level of curtailable demand that could respond to prices was surveyed, indicating that 600–800 MW could do so, without any formal demand response programs. The market policy framework indicated that metering improvement and alignment between the settlement and dispatch intervals should be considered to encourage more demand response.[28] Many of the initiatives the AESO has undertaken since then have been in response to the policy framework.

From 2008 to 2009 the AESO conducted a demand response working group in which a number of topics related to load participation in the market were reviewed, including the levels of existing demand response, barriers to additional demand response, and finally what the requirements would be for demand to participate in AESO-procured ancillary services.[29] Through this process the AESO developed principles for demand response initiatives, including the following.

- Barriers that impede or preclude DR should be examined to determine if any can be removed / reduced. When possible equivalent or symmetric market rules for load and generation should be created.
- New products or services should be designed such that when technically feasible, both loads and generators will be eligible to compete to provide the service. The design of these products is to be consistent with Alberta's real-time energy only market design, where the real-time price is the signal for load to curtail in the energy market.
- Participation by both generation and load in AS products should be allowed whenever technically possible.

Starting in 2009, the AESO started recording and reporting load outages as a result of legislative requirements to ensure equal access to outage information to facilitate trading. The disclosure of this outage information is designed such that participants are eligible to trade

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Continued from previous page

26 A review of all offers made between 2010 and 2015 has indicated that no demand resources have bid into the energy market. AESO, "Merit Order Snapshot – Energy Report," Daily, from Jan. 1, 2010 to May 31, 2015. http://ets.aeso.ca/.

27 Provence of Alberta, *Alberta's Electricity Policy Framework: Competitive—Reliable—Sustainable*, June 6, 2005, p. 4–5, http://www.energy.alberta.ca/Electricity/pdfs/AlbertaElecFrameworkPaperJune.pdf.

28 *Ibid*, p. 40.

29 AESO, *Alberta Demand Response Initiative Discussion Paper*, October 22, 2009, http://www.aeso.ca/downloads/Demand_Response_Discussion_Paper_-_Final_(3).pdf.

around this information and is symmetric to rules around trading on generator outage information.

In response to system needs, in 2011 the AESO introduced a new ancillary service product, "Load Shed Service for Imports" (LSSi) which is designed to increase import capabilities over the interconnection between Alberta and its neighbours in the Western Electricity Coordinating Council (WECC), British Columbia (BC), and Montana.[30] This is achieved as loads participating in the LSSi program are armed to be rapidly tripped offline by automatic relays in response to a reduction in frequency following a trip on the interconnection. By having LSSi in place, the system operator is able to loosen reliability-based import limits and additional imports are able to flow. LSSi replaced existing load shed services in response to low frequency that were not competitively procured.

In 2011 the AESO also revised its technical requirements to allow load aggregators to participate in the supplemental (non-spinning) reserves market.[31]

In response to the approval of a reliability standard (BAL-002) in 2014 by the Alberta Utilities Commission, the AESO initiated consultation on the technical requirements necessary for loads to provide spinning reserves.[32] This effort is ongoing and final rules are expected to be drafted in a forthcoming consolidated set of rules for ancillary services.[33]

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30 Alberta has two interconnections with the rest of WECC, a larger path with British Columbia, and a smaller with Montana. If the B.C. path is out of service then Alberta is functionally separated from the rest of the WECC grid.

31 AESO, *Operating Reserves Technical Requirements: Technical Requirements for Provision of Supplemental Reserves by Loads*, Version 3.0, November 1, 2011, http://www.aeso.ca/downloads/Technical_Standards_for_the_Provision_of_Supplemental_Reserve_Load.pdf.

32 AESO, *Enabling Load to Provide Spinning Reserve*: Revision of Spinning Reserve Technical Requirements and SCADA Technical and Operating Requirements, July 24, 2014, available at http://www.aeso.ca/downloads/Enabling_Load_to_Provide_SR.pdf.

33 AESO, "AESO Replies to Stakeholder Comments on OR Papers," September 4, 2014, p. 5, http://www.aeso.ca/downloads/AESO_replies_to_stakeholder_comments_on_OR_papers(1).pdf.

Figure 8
History of Demand Response in Alberta

2. Demand Response Provision of Ancillary Services

The AESO is the sole buyer of ancillary services and procures three operating reserve products (regulating reserves, spinning, and supplemental / non-spinning) in a day-ahead market.[34] In addition to the operating reserves the AESO also procures additional ancillary services including LSSi through requests for proposals. The LSSi product is further discussed below; the remainder of this section focuses on demand participation in the operating reserves market.

Currently, individual or aggregated loads of 5 MW or greater are qualified to provide supplemental reserves.[35] Since 2013, five individual loads and one aggregator have participated in this market. The maximum level of participation of the five individual loads has been approximately 120 MW, and 60 MW from aggregated load. Of the five individual participants, three are chemical loads, and two are pulp and paper loads. Load participation accounts for an average of 17 per cent of the AESO's daily supplemental reserve requirement, and has provided over 50% of the requirement on at least ten days in 2014.[36] This is similar to the participation in supplemental reserves by combined cycle generators.

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34 The AESO also has the option to procure these reserves over-the-counter if necessary. (AESO Rule 205.1.4.).
AESO, Current ISO Rules, April 1, 2015, Section 205.1 Offers for Operating Reserves (http://www.aeso.ca/downloads/Division_205_-_Section_205-1_Offers_for_Operating_Reserve_(Dec_23_2014).pdf),p. 2, online at http://www.aeso.ca/rulesprocedures/18592.html.

35 AESO, *Operating Reserves Technical Requirements*, *op.cit.*.

36 Statistics based on a review of the AESO's Operating Reserves Offer Control Report from Jan., 2013 to May, 2015

In early 2014 the provincial regulator approved a reliability standard (BAL-002) developed in response to industry-wide changes that include allowances for loads to provide spinning reserves, in addition to supplemental reserves, as long as the load meets the technical requirements. Large transmission-connected loads of 10 MW or greater are, as of late 2014, enabled to provide spinning reserves,[37] though none have done so to date.[38] The AESO initiated an exploration of a number of issues with contingency reserves including the size of asset required to provide spinning reserve, and whether to allow aggregation for spinning reserves. This initiative is currently underway.[39] The AESO is currently considering the optimal size of assets that can provide spinning reserves so that they are capable of arresting frequency decay during a contingency event. In this process the AESO will also consider the potential for aggregated loads participating in spinning reserves.[40]

The operating reserves market clears day-ahead and the market clearing price is a discount or adder to the real-time pool price. Since 2013, loads that participate in supplemental reserves have received on average $CAD 49/MWh, though depending on the month and underlying pool price have received anywhere between $7 and $153/MWh for the service over an individual month.[41] If a load were to provide spinning reserves then it may achieve slightly higher value for the service as monthly spinning reserve prices are on average 23 per cent higher than the price that load has realized in participating in the supplemental reserves market.[42] To date, no large industrial loads have been active in the spinning reserves market. This could be in part due to 1) the additional technical requirements that loads have to meet to participate in spinning reserves, and 2) the relatively small difference in value between the two products.

Relative to only responding to price in the energy market, a load that participates in the AS market is paid for its availability. Therefore by providing AS the load receives some payment and will probably be able to continue to operate as normal, unless it is called. By participating in the AS market, the load does bear the risk of having to curtail when the system controller

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37 AESO, Current ISO Rules, April 1, 2015, Section 205.5: Spinning Reserve Technical Requirements and Performance Standards." March 27, 2015 (http://www.aeso.ca/downloads/Division_205_-_Section_205-5_Spinning_Reserve_Technical_Requirements_and_Performance_Standards_(March_27_2015).pdf).

38 Based on a review of the AESO's Operating Reserves Offer Control Report from Jan. 2015 to May, 2015.

39 AESO, "AESO Responses to Comments from Stakeholders Regarding the *Directive Performance Requirements for Operating Reserves* Paper and the *Enabling Load to Provide Spinning Reserve* Paper," September 4, 2014, http://www.aeso.ca/downloads/Dir_Perf_Req_Enabling_Load_Comment_Response__Cover_Letter(1).pdf.

40 *Ibid.*

41 Based on the realized price of supplemental reserves provided by loads between Jan. 2013 and May 2015. Source: AESO Market Data.

42 Based on a comparison of the realized monthly average supplemental price received by load to the average monthly supplemental reserves price. Source: AESO Market Data.

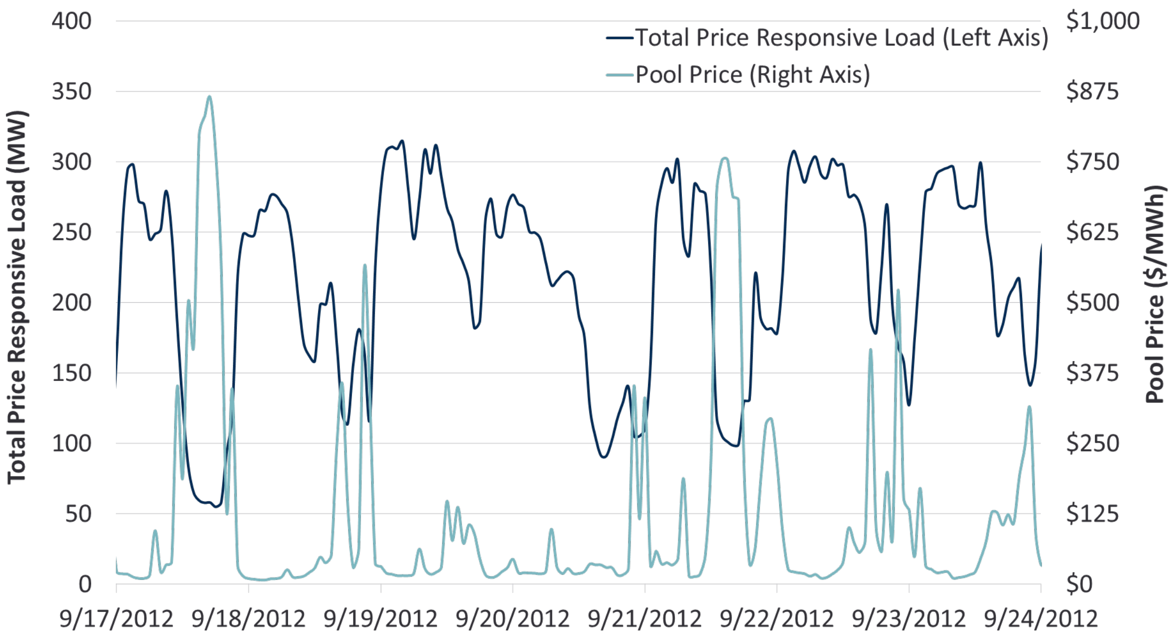
directs the load in response to a contingency event. In 2013 and 2014, loads that were providing supplemental reserves were curtailed in a total of 45 hours.[43] When directed, load must reduce consumption within 10 minutes. Loads that provide reserves also have to maintain a control centre that is staffed 24/7.

3. Dispatching in the Presence of Non-Bidding Demand Response

Loads are eligible to bid into the market but at this time none does. However, a number of large industrial consumers respond to the real-time price signal by reducing consumption when prices increase. The AESO has identified a set of large, transmission connected industrial loads that respond to price. The consumption of these loads are actively monitored by the system operator in real-time, and are referred to as "price-responsive loads" in Alberta. This behaviour is solely promoted through market price signals and these loads are not compensated for this behaviour. The AESO has stated that additional compensation for participation in the energy market should not be given as it would distort the price signal, which alone should suffice to entice demands to respond to price.[44]

Figure 9 illustrates an example of the price responsive behaviour seen in the Alberta market and Figure 10 illustrates the general association between the consumption of these price responsive loads and prices from January 2007 through September 2012. It clearly shows that upwards of 200 – 300 MW of load typically comes off once prices exceed $100/MWh.

Figure 9
Illustrative Example of Demand Response Behaviour

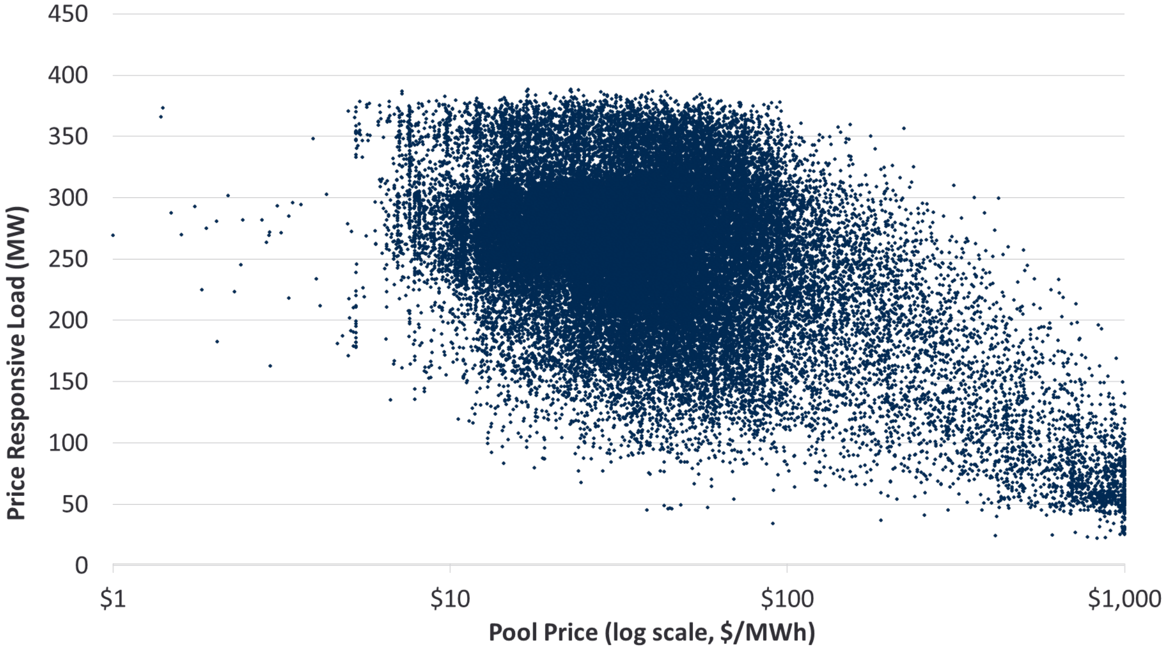


Source: AESO Demand Response Data, AESO Pool Prices

[43] Based on hourly directive amounts for supplemental loads between loads between Jan. 2013 and May 2015. Source: AESO Market Data.

[44] AESO, "AESO Demand Response Discussion Paper: Stakeholder Comment Matrix," December 17, 2009, http://www.aeso.ca/downloads/DR_Comment_Response_Matrix_-_December_17_2009_.pdf

Figure 10
Hourly Pool Price and Price-Responsive Load: Jan. 2007 – Sept. 2012



Source: AESO Demand Response Data, AESO Pool Prices

A load that followed the price responsive pattern of behaviour illustrated above would have reduced their energy costs by 23% over the period presented.[45]

These price responsive loads, while not submitting bids to the market, are considered by the AESO in preparing its demand forecasts and do influence market outcomes. Without the load response market prices would be higher as higher cost generators would have to be dispatched. This pattern of behaviour by these price responsive loads has been very consistent over multiple years, and the AESO includes price responsive load in its short term adequacy assessment that it performs for the next seven days.[46]

The AESO allows some load to connect under a special class of system access known as Demand Opportunity Service (DOS). This access is interruptible, temporary, and only available if there is sufficient surplus transmission capacity.[47] Once approved these loads are

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45 This result is based on comparing the load-weighted average price that the price-responsive loads illustrated in Figure 17 and Figure 18 would have realized between Jan. 2007 and Sept. 2012 against the simple average pool price during the same period.

46 AESO, Current ISO Rules, April 1, 2015, Section 202.6 Adequacy of Supply (http://www.aeso.ca/downloads/Division_202_-_Section_202-6_Adequacy_of_Supply_(Oct_1_2014).pdf), online at http://www.aeso.ca/rulesprocedures/18592.html.

47 AESO, "Business Practice Document: Demand Opportunity Service," 2011, p. 2, http://www.aeso.ca/downloads/DOS_Business_Practice_Document.pdf.

interruptible in the event of system reliability concerns. In 2010 and 2011 (the last years for which data is available) the AESO reported that 132 MW of load was under DOS contracts.[48].

4. Demand Bid Participation

Having demand bid into the market would reduce reliance on the system operator's load forecast. This presumably comes at a cost for loads as they would be subject to market rules with respect to submitting bids and following dispatch.

In Alberta, price responsive loads haven chosen not to bid into the market and instead closely monitor the market price that the AESO posts in real-time. If these loads chose to, they could submit bids into the market and receive dispatches from the system controller. If that were the case then the loads would have to submit up to seven price-quantity pairs, abide by AESO rules for submissions to ETS, and respond to dispatches in real-time. Compliance obligations to consume within an allowable dispatch variance would have to be met.[49] As there is currently no incentive to do so, it is understandable that these loads would continue to voluntarily limit their consumption when prices increase to avoid regulatory burden and compliance risk that they would face if they did submit bids. Bidding is also viewed to be difficult by loads as they may not be capable of ramping back up to respond to a dispatch.[50]

There is a disconnect between dispatching in real-time and hourly settlement which impacts generators and would also impact loads that bid. For example, suppose a generator offered to produce 10 MW when prices are greater than $100/MWh, and an additional 10 MW when prices exceeded $500/MWh. If the higher priced offer was dispatched for half an hour and the market (pool) price settled at $300/MWh then the generator would not be fully compensated at the price it offered to provide its energy as settlement would be based on the pool price. For generators this issue was identified in the 2005 Market Policy Framework and the AESO introduced a settlement rule in 2007 to pay marginal generators their offer price when they are dispatched above the market clearing price.[51] In this case the generator would

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48 AESO "2011 Annual Market Statistics Data File," February 16, 2012, http://www.aeso.ca/downloads/2011_Annual_Market_Stats_Data_File.xls.

49 For generators, dispatch variance is measured every 10 minutes, and if the average is outside of its allowed level then the matter would be referred to the Market Surveillance Administrator for penalty evaluation.
AESO, Current ISO Rules, April 1, 2015, Section 203.4 Delivery Requirements for Energy," December 23, 2014 (http://www.aeso.ca/downloads/Division_203_-_Section_203-4_delivery_requirements_(Dec_23_2014).pdf), online at http://www.aeso.ca/rulesprocedures/18592.html.

50 The Brattle Group, "Demand Response Review Presented to AESO," March, 2011, Slide 31, http://www.aeso.ca/downloads/Brattle_RTO_DR_Review_Final.pdf , slide 31.

51 The settlement rule is known as payments to suppliers on the margin (AESO Rule 103.4.6).
AESO, Current ISO Rules, April 1, 2015, Section 103.4 Power Pool Financial Settlement (http://www.aeso.ca/downloads/Consolidated_ISO_Rules_April_1_2015.pdf), online at http://www.aeso.ca/rulesprocedures/18592.html.

be paid \$300/MWh for the first 10 MW dispatched across the full hour and \$500/MWh for the incremental 10 MW dispatched for half an hour.

In the demand response working group it was suggested that loads that bid could be eligible for a similar payment and that this could be one incentive to encourage active market participation. The process would work as follows.

- A load bids to consume 10 MW up to \$250/MWh and none when the real-time price exceeds this level.
- In a particular settlement hour, prices are \$50/MWh for the first half of the hour (and the load consumed 10 MW), and then \$950/MWh for the next half an hour (and the load bid was dispatched, its consumption being 0 MW). The market settlement price is then \$500/MWh (and the load's energy consumption for the hour was 5 MWh). The total settlement under standard rules for the hour would be \$500/MWh × 5 MWh = \$2,500 paid by the load. (Note that this would also be the outcome if the load did not bid.)
- If the energy consumption charge was based on real-time consumption multiplied by real-time prices, the settlement for load would have been 0.5 hours × 10 MW × \$50/MWh + 0.5 hours × 0 MW × \$950/MWh = \$250 (again, paid by the load). This illustrates the sizable impact of the difference between the settlement and dispatch interval.[52]
- The analogue to the generator rule would pay the difference between the pool price (\$500/MWh) and the offer price (\$250/MWh) multiplied by the load's response to its bid being dispatched. The payment would then be \$250/MWh × 5 MWh = \$1,250. This would net off against total settlement for the hour, reducing it by half (\$2,500 - \$1,250 = \$1,250). This is still higher than real-time pricing, but a notable improvement than not bidding and just responding to the price signal.

The AESO has not made any rule changes to adopt this type of payment to demand bids on the margin so it cannot be assessed if any loads would be incentivised by this type of settlement payment. Demand participants have not been active in requesting this type of incentive, perhaps because the compliance obligations that would come with bidding could outweigh the benefits of improved settlement. In the longer term, one of the AESO's policy objectives is to move to a more aligned settlement and dispatch period (most likely through shorter settlement periods).[53]

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52 Note that based on the bid, the load would be willing to consume 10 MW for a full hour if the price was at \$250/MWh (i.e., willing to pay up to \$2,500 for 10 MWh of consumption).

53 Properly aligning dispatch and settlement periods is an outstanding issue from the 2005 Market Policy Framework. The AESO has noted that shorter settlement intervals that better match dispatch periods are only possible with new market I.T. systems. AESO, "AESO Consultation—2013 Budget Review Process: Market Systems Replacement Project—Special Funding," Stakeholder Comment and AESO Replies Matrix, March 7, 2013, http://www.aeso.ca/downloads/MSR_Validation_-_BRP_Comments_Reply_Matrix_final.pdf.

It has been suggested that the AESO price cap of $1,000/MWh may also act as a disincentive for load to bid since Alberta has high levels of industrial demand that may have a very high value of lost load.[54]

5. Load Shed Service to Increase Imports

The "Load Shed Service for Imports" (LSSi) program was designed to support the amount of imports Alberta is able to receive over its interconnections with British Columbia (B.C.).[55] This is necessary as at high levels of imports the interconnection with B.C. becomes the single largest contingency, and the loss of the interconnection would de-synchronize Alberta from the rest of the grid. LSSi participants are willing to be tripped (via automatic relays) after the immediate loss of imports that may occur if there was a contingency on the interconnection. This mitigates the risk of frequency deviations and allows for higher levels of imports. The program was designed as part of a larger initiative to restore the interconnection to its path rating, and also met the demand response program principles.

Load response supported imports on the interconnection prior to the implementation of LSSi through other programs, and the LSSi program was designed to address issues in these earlier programs. These were:

- Import load remedial action scheme (ILRAS), where loads that could be interrupted were armed by the system operator when there was a supply adequacy concern to allow for higher imports. Loads were not compensated for availability, only if tripped.
- Load shed service (LSS) was procured by the AESO from large industrial loads. Participation in the program meant that loads were always available and armed and could be tripped either by system operator directives or when frequency dropped.

Under these two prior approaches the level of service that the AESO required was not garnering enough interest and procurement was not competitive. In addition, loads were not in control of whether they were armed and thus taking on the risk of being tripped offline at any time. The LSSi contract allows loads to determine whether or not they want their load to be armed for each hour of the day, and how much load is to be armed. Specifically, loads are able to adjust how much load is available, but once armed must consume between 90 per cent

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54 AESO, "Alberta Demand Response Initiative Discussion Paper," October 22, 2009, p. 14; Pfeifenberger, J.P., K. Spees, and M. DeLucia, *Evaluation of Market Fundamentals and Challenges to Long-Term System Adequacy in Alberta's Electricity Market: 2013 Update*, The Brattle Group, March 2013, p. 44, http://www.brattle.com/system/news/pdfs/000/000/041/original/Evaluation_of_Market_Fundamentals_and_Challenges_to_Long-Term_System_Adequacy_in_Alberta_Pfeifenberger_et_al_Mar_2013.pdf?1377791284.

55 Provincial legislation requires that the AESO to restore the interconnection with B.C. to its path ratings of 1,200 MW for Import and 1,000 MW for export (Transmission Regulation 086-2007). Currently due to intra-Alberta constraints and reliability needs the path rating is limited, and prior to the implementation of LSSi available transfer capability (ATC) on the interconnection was less than half of the path rating.

and 120 per cent of their armed amount,[56] and be able to be disconnected from the grid within 12 cycles (0.2 seconds). To do so a load must be greater than 1MW, have under-frequency relays installed at each site to detect when frequency drops below 59.5 Hz, and have real-time SCADA connectivity to the system operator.

The program provides a three part payment structure. Loads are compensated when they are consuming and make their load available for arming ($5/MW/h). This availability payment is paid in hours that the LSSi provider chooses to make their load available and is based on the lowest level of load within the hour. In hours that the load is armed, the load is paid its arming price which is set in the sealed bid RFP process. An additional payment is made when they are tripped ($1,000/MW per trip). While the individual arming prices are not public, the MSA indicated in its initial analysis of the LSSi program over Q2 2012 the arming payment was on average $36/MW/h.[57] Assuming that the load is tripped once per year and is armed for two hours, a load that participated in the program and was available in all hours of the year would have made approximately $120/kW-yr.

The structure of the program resulted in a competitive level of interest from industrial and commercial loads and aggregators. The expression of interest for the 485 MW requirement saw 700–800 MW of load interested and a total of 432 MW were contracted in the initial RFP process. The AESO recovers the cost of this ancillary service through its transmission tariff, in a similar manner to other ancillary services costs.[58] The increase in low cost supply through imports offsets the added cost of this service.

The LSSi program was initiated in late 2011 and has been successful in increasing import capability. In its first year, participating loads had at least 100 MW available to be armed in 85 per cent of the hours, and the system operator armed LSSi to increase import capacity in 23.5% (2,059) hours. In hours that LSSi was armed, an average of 137 MW was armed. This resulted in increasing the maximum import capacity of the Alberta-B.C. interconnection to 700MW over the year, 50 MW higher than the maximum in any of the three previous years. The AESO found in its review of LSSi that the increased import capacity led to an additional 103,000 MWh of imports into the Alberta market between April 1, 2012 and March 31, 2013.[59]

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56 This requirement is expected to change to 150% on the high level of the tolerance bound. The low level is essential to ensure enough load response is available to arrest frequency decay. See AESO, *Assessment of Load Shed Service for Import (LSSi) Product*, March 27, 2014, http://www.aeso.ca/downloads/Review_of_Load_Shed_Service_for_Import_Product_Final.pdf

57 Alberta Market Surveillance Administrator (MSA), "Quarterly Report: April–June 2012 (Q2/12)," August 20, 2012, available at http://albertamsa.ca/uploads/pdf/Reports/Quarterly%20Reports/MSA%20Q2%202012%20FINAL%20120830.pdf.

58 AESO, Recovery of Costs of Load Shed Service for Imports (LSSi), presented by Raj Sharma, Calgary, May 22, 2013, p. 9, http://www.aeso.ca/downloads/2013-05-22_AESO_2014_Tariff_Consultation_-_LSSi_Cost_Recovery_Handouts.pdf.

59 AESO, "Assessment of Load Shed Service for Import (LSSi) Product," March 27, 2014, Figure 1, p. 7.

Some of the load participating in LSSi are the same loads that respond to energy prices and/or that participate in the operating reserves market. The AESO has rules in place that the same MW that is sold in the operating reserves market cannot provide LSSi. Also, since load is required to consume to be capable of providing LSSi, loads must choose between participating in LSSi and responding to real time energy prices. At high market prices it is likely that LSSi payments would be smaller than avoided energy charges (unless the load is actually tripped). This creates a dilemma for the LSSi program as it is precisely at the time that there are high prices, that additional import capacity is beneficial. The MSA noted this as a concern in the initial months of the program.[60] In reviewing the levels of LSSi at high market prices the AESO found that for the 5 per cent of hours where the pool price was above C$300/MW, on average only 50MW of load was made available, though LSSi was only armed in less than 20 per cent of these high priced hours.[61] A mixture of price-responsive load and non-price responsive loads (including aggregators) participate in the LSSi program, and these results suggest that there is some certainty that there will be loads available to be armed.

C. ERCOT

The Electric Reliability Council of Texas (ERCOT) opened retail markets to competition in 2002. ERCOT operates day-ahead and real-time energy markets with a current price cap of $9,000/MWh (AUD $12,203/MWh). In contrast to PJM and ISO-NE, ERCOT does not have a resource adequacy requirement and thus does not operate a capacity market. Additionally, due to the fact that the market is not synchronized with the rest of the United States, ERCOT is largely not subject to oversight by the Federal Energy Regulatory Commission (FERC).[62]

The ERCOT market enables several types of demand response. First, Load Resources provide approximately 1,400 MW of Responsive Reserves to be deployed if frequency falls below threshold levels. Second, ERCOT has also recently allowed qualifying Load Resources to submit bids to buy in its energy market dispatch (although participation is currently minimal). Third, Emergency Response Service (ERS) is basically a capacity resource that is paid an availability payment to be deployable in system shortages, with approximately 400 MW participating. Loads providing ERS are deployed via a direct signal from the system operator. These are the only programs administered by ERCOT, but some load also responds to real-time prices (we have estimated at least 700 MW of load reduction during high-priced periods).[63] Large customers also adjust their consumption during peak demand periods in order to manage their transmission charges.

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60 MSA, "Quarterly Report: April-June 2012," August 20, 2012, p. 18.

61 AESO, "Assessment of Load Shed Service for Import (LSSi) Product," March 27, 2014, Figure 4 p. 11.

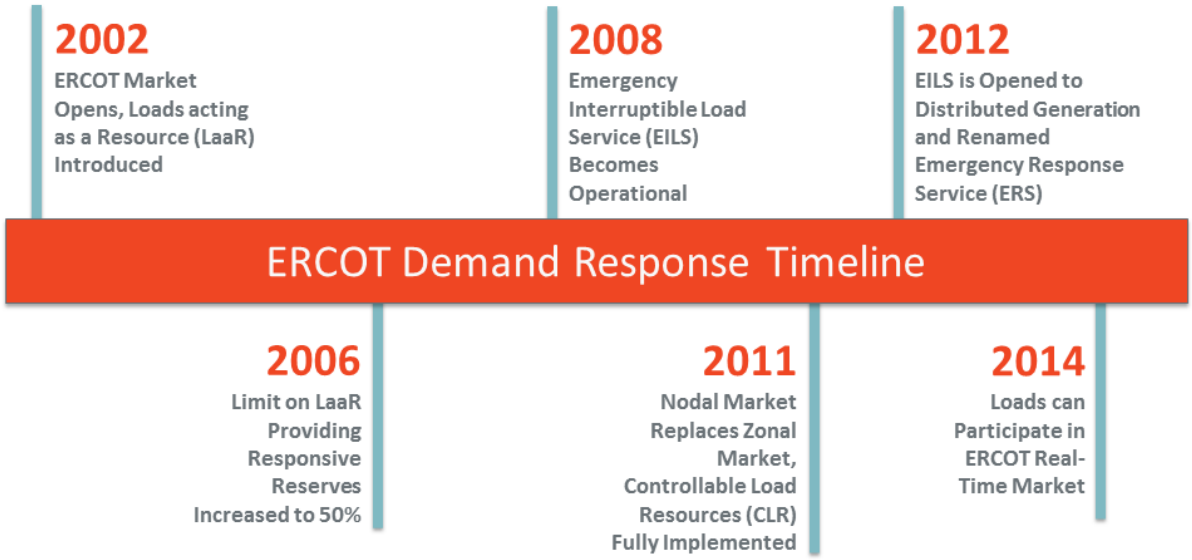
62 Federal Energy Regulatory Commission (FERC), ERCOT, online at https://www.ferc.gov/industries/electric/indus-act/rto/ercot.asp.

63 Newell, S.A., K. Spees, *et al.*, *Estimating the Economically Optimal Reserve Margin in ERCOT*, The Brattle Group, January 31, 2014, available at http://www.brattle.com/system/publications/pdfs/000/004/978/original/Estimating_the_Economically_Optimal_Reserve_Margin_in_ERCOT_Revised.pdf?1395159117.

1. Timeline and Status of Demand Response Developments

Since 2002, ERCOT has allowed DR to participate in ancillary service markets through the Load acting as a Resource (LaaR) program. ERCOT subsequently created the Emergency Interruptible Load Service program to pay DR for its availability to be curtailed in the event of an emergency. In addition to these formal DR programs, loads in ERCOT react to real time energy prices and various peak-demand related charges. ERCOT is currently engaged in efforts to better integrate DR into its energy markets. We discuss each of these issues in the sections below.

Figure 11
History of Demand Response in ERCOT



2. DR Providing Ancillary Services

Under the LaaR program, loads were eligible to provide Responsive Reserves in the ERCOT market. LaaR participants had to meet similar requirements to generators for providing AS, including installing telemetry equipment and demonstrating their ability to respond to dispatch instructions on the required timeframe. Load was initially limited to providing 25% of the total Responsive Reserve requirement, but this limit was increased to 50% by 2006.[64]

In 2011, ERCOT finalized its implementation of the Controllable Load Resources (CLR) program. The CLR program has more stringent requirements for participation, enabling loads to provide regulation services as well as reserves, and to avoid the caps on participation of LaaRs in the responsive reserve market. CLRs must be able to both respond automatically to frequency changes in a manner similar to generator governor control, and respond to 2-second signals from the system operator in a manner similar to generators equipped with

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64 Electric Reliability Council of Texas (ERCOT), "The History of Load Participation in ERCOT," presented by Mark Patterson, presented at DOE Workshop, Washington, DC, October 25, 2011.

Automatic Generation Control.[65] However, our understanding is that only a minimal amount of resources participate as CLR currently, with approximately 50 MW of qualified CLRs in 2014.

ERCOT's Ancillary Service load programs were not created with the goal of achieving a particular DR penetration target, but rather to allow load to provide a valuable service to the system. By working to ensure that loads and generators met similar qualifying requirements, ERCOT avoided the potential for an implicit subsidy of load resources in its AS markets. Nevertheless, the programs have achieved substantial DR penetration in AS markets. While there are many reasons for the success of these programs, ancillary service markets would seem in many ways to be a natural fit for load resources. Ancillary service markets provide a reliable availability payment. Additionally, because reserves are not deployed frequently, loads do not actually have to change their consumption patterns very often.

3. "Emergency" Demand Response within an Energy-Only Construct

In the spring of 2006, ERCOT was forced to shed load for the first time since the market opened. A combination of factors including under-forecasted load, substantial generation on planned outage, and a series of unit trips, led to rotating shedding of firm load for two hours. ERCOT concluded that it could have avoided outages if it had been able to curtail some load part way through the emergency. ERCOT decided to create an emergency product, called Emergency Interruptible Load Service (EILS), which could be deployed in an emergency prior to shedding firm load.

Under EILS, and its successor the Emergency Response Service (ERS) program, participating loads are paid for their availability to be curtailed (via direct signal from ERCOT) in the event of an emergency. This availability payment is somewhat similar to the payment received by loads participating in capacity market DR programs. However, the period when participants in ERS are required to be available is not limited to the summer. The program includes several availability periods in which participants can register. In each one, resources can be activated in response to generation and transmission outages or extreme weather events.[66]

In the event of an emergency, EILS resources could be called by ERCOT to curtail within 10 minutes. Participants could choose to be available during one of three business day time periods or during non-business days. EILS resources were procured through a four-month auction process occurring three times a year. Participants submitted bids and participants received bid prices for their availability up to a maximum procurement cost of $50M per

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65 ERCOT, "Controllable Load Resource (CLR) Participation in the ERCOT Market: Addendum to Load Participation in the ERCOT Market," prepared by the Demand-Side Working Group of the ERCOT Wholesale Market Subcommittee

66 ERCOT, "ERCOT Emergency Interruptible Load Service, Overview," Updated July 2009.

year.[67] Participants do not receive any additional payment in the event of a curtailment. Both individual loads and aggregators were eligible to participate.[68,69]

In 2012, ERCOT sought to increase the size of its emergency DR program. It made a series of changes to EILS, including changing the program's name to the Emergency Response Service (ERS). Unlike EILS, the new ERS was open to participation by distributed generation resources. ERS also had a lower minimum facility size (of 0.1 MW compared to 1 MW) in order to allow aggregation of smaller facilities.[70]

Additionally, ERS sought to correct a problem with EILS that could leave ERCOT with little contracted capacity following a long deployment. Under EILS, participants were required to be available for a maximum of two deployments and a total of eight hours during each contract (four month) period. While loads were not allowed to come back online until released by ERCOT, even if the deployment lasted longer than the eight hour limit, loads would not be required to respond for the remainder of the contract period following such a long deployment. Under ERS, facilities could opt-in to have their contract automatically renewed in the event their obligation expired during the initial contract period.[71]

ERCOT has made several changes to the ERS program since it was originally introduced. ERS-30, a resource able to respond within 30 minutes of activation, was added to the existing ERS-10 capacity. In 2013, ERCOT initiated a Weather-Sensitive ERS pilot program. The pilot program, which ran from June to September of 2013, was intended to evaluate the potential for weather sensitive loads (such as air conditioner) to participate in ERCOT's emergency DR programs.

ERCOT's procurement mechanism involves generating a demand curve based on an annual expenditure limit of $50 million. The ISO allocates its total available funds across the three annual auctions according to its assessment of the relative risk of an emergency event occurring in each of the three periods. The June to September auction usually has the highest risk assessment and therefore receives the largest share of the expenditure limit. In an example calculation provided by ERCOT in its Emergency Response Service Procurement Methodology, the June through September auction had an expenditure limit of approximately $30 million, with the other two auctions having expenditure limits of approximately $10 million each.

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67 *Ibid.*

68 A technicality: all participants either had to be, or be represented by, an ERCOT Qualified Scheduling Entity (QSE). QSEs must submit balanced buy-sell schedules. There are nearly 500 QSEs registered in the ERCOT market.

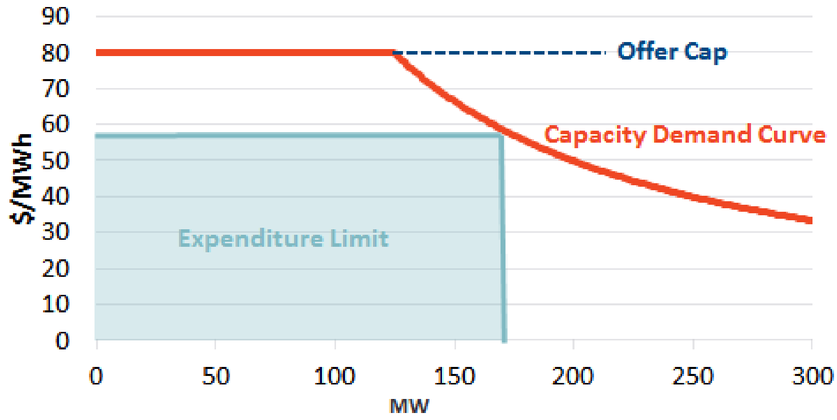
69 ERCOT, "ERCOT Emergency Interruptible Load Service, Overview," Updated July 2009.

70 ERCOT, ERCOT Demand Response, presented by Paul Wattles, presented at Whitacre College of Engineering, Texas Tech University, April 6, 2012.

71 ERCOT, *Emergency Response Service Technical Requirements & Scope of Work: Standard Contract Term: June 1, 2015 through September 30, 2015*, April 3, 2015.

Auction payments are made in $/MW/h and are uniform for loads available during different parts of the business week (e.g. loads available 8 AM–1 PM on business days receive the same payment per hour as loads available 2 PM–5 PM weekdays, though their total payment is higher as they are available during more hours). The auctions have an offer cap of $80/MW/h. Figure 12 shows a representative June–September ERS auction demand curve generated using a time period total expenditure limit of $30 M. Cleared volumes of ERS-10 ranged from 450 MW to 630 MW across the 3 yearly auctions and 4 weekly availability periods. Cleared volumes of ERS 30 ranged from 100 MW to 280 MW.[72]

Figure 12
ERS Auction Demand Curve Example



Sources and Notes:
Adapted from: ERCOT, "Emergency Response Service Procurement Methodology," Nov. 2013
Uses an offer cap of $80/MW/h.
Uses a total period Expenditure Limit of $30 Million, which leads to an hourly Expenditure limit of $9,972/h based on the 2,928 hours in the June-September period.

While ERCOT's ancillary service and emergency DR programs were intended to improve reliability, these resources had the potential to produce counter-productive side effects during scarcity events. Unlike generation resources, DR resources are usually deployed outside the market—either through direct response to frequency or through a signal from the ISO (though this is starting to change—see further discussion below). When these resources were deployed, real time load decreased, but ERCOT's market clearing software did not recognize that it had been actively curtailed. This could lead to a drop in real time energy prices in the midst of a scarcity event.

ERCOT's market monitor reported an example of falling real time energy prices during a load curtailment in its 2014 report.[73] On August 4th, 2011, prices reached the then price cap of $3,000/MWh shortly after 1:00 PM. Load reserves were deployed at 2:30 and by 4:00 PM, the system was more than 1,000 MW short of its reserve target. Shortly after 4:30, following

[72] ERCOT, *Annual Report of Demand Response in the ERCOT Region*, Version 1.0, March 2015, p. 5.

[73] Potomac Economics Ltd., *2014 State of the Market Report for the ERCOT Wholesale Electricity Markets*, July 2015.

increasing load response, real time prices began to fall. By 5:30, prices had fallen below $100/MWh despite a more than 500 MW reserve shortfall.

Clearly, prices should not fall during a supply shortfall. As ERCOT's market monitor indicated in its 2014 report, when load is not served due to emergency conditions, "the energy price should reflect the value to load of not being served."[74] In the short run, prices need to remain high to encourage additional supply to be brought online. In the long run, and particularly in an energy-only market like ERCOT, high prices are needed to encourage investment in peaking capacity.

ERCOT has recently begun to address this situation. First, the ISO has implemented administrative pricing mechanisms to account for out-of-market deployment of DR. These mechanisms adjust prices upwards to account for the DR deployment.[75] Second, the ISO has begun to implement mechanisms to encourage additional direct participation of DR in the energy market.

4. Load Participation in Energy Markets

a. Current Status

Much of the energy market Demand Response in ERCOT is provided by loads responding in some way to real time prices. Many large commercial and industrial loads purchase a block of energy at a fixed price, and assume some wholesale market price risk for the remainder of their consumption (the "block and index" model). Some loads not in the category of large commercial and industrial customers also have exposure to wholesale market prices. Many Retail Electric Providers in ERCOT offer Time of Use pricing, real-time pricing, and critical peak pricing to their customers. The Brattle Group has estimated that at least 700 MW of demand reduction during peak periods is provided by such loads.[76]

In ERCOT's market construct, price-responsive load helps to balance supply and demand and contributes to price formation (during scarcity events) via ERCOT's Operating Reserve Demand Curve. However, because price-responsive loads can only respond after prices are posted, its actions may lag the market somewhat. This lag may cause price-responsive load to be somewhat less efficient than loads actively bidding their demand into the market.

In 2014, ERCOT began allowing Controllable Load Resources (CLRs) to participate in the real-time energy market by submitting demand-side bids.[77] CLRs participating in the real-time market in this way are required to follow a 5-minute dispatch signal from the system

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74 *Ibid.*, p. xxvi

75 626 NPRR-12 Board Report 081214 Public, Reliability Deployment Price Adder (Formerly "ORDC Price Reversal Mitigation Enhancements"), online at http://www.ercot.com/mktrules/issues/NPRR626#summary.

76 Newell, S.A., K. Spees, *et al.*, *Estimating the Economically Optimal Reserve Margin in ERCOT*, The Brattle Group, January 31, 2014.

77 ERCOT, *Load Participation in the ERCOT Nodal Markets: A plain English guide to ERCOT's wholesale market Demand Response products and services*, Version 3.02, April 23, 2015.

operator and will avoid the cost of procuring energy in the market. This will result in payments equivalent to the wholesale price minus an estimate of the avoided retail cost (this approach is termed "LMP minus G", as we discuss further below).[78]

Though ERCOT's stated goal in allowing CLRs to bid was to "help limit Real-Time price reversal when actions are taken by ERCOT for reliability purposes," the program may also result in additional load bidding into the energy market.[79] Active participation in the energy market in this way has the advantage that the load is guaranteed to be paid the price at which it is dispatched and therefore has more price certainty.

b. Ongoing Evolution

ERCOT has already made some progress to introducing load in its energy market dispatch. Participation remains very low, but further reforms are under discussion with the aim of increasing it. Several limitations of the current approach must be addressed to achieve this goal. Current rules require all loads bidding into the energy market to respond to a five-minute dispatch signal and according to ERCOT's market monitor, much of the ISO's load cannot respond in this way. Current rules also do not allow aggregators to participate directly, requiring that they be represented by a retailer. Additionally, under current rules, loads bidding into energy market cannot provide ancillary service if they have minimum or maximum run times.

5. Other Forms of Load Response in ERCOT

The four 15-minute periods with the highest coincident demand in each of the four summer months (Jun–Sep) are known as the Four Coincident Peaks (4CP). ERCOT utilities recover transmission costs from large commercial and industrial loads (and from some municipal and cooperative utilities) based on their demand during these periods. These loads pay a T&D charge the following year proportional to their load on the four coincident peaks this year. They therefore have an incentive to anticipate the occurrence a peak period and reduce their consumption. Large industrial loads may be able to reduce their transmission charges by more than $40,000 per year for each MW they curtail on the four coincident peaks.[80] While 4CP is not a formal demand response program (we do not record it in Figure 3), the incentive structure has triggered approximately 500 MW of peak reduction from affected loads during peak periods.[81]

These peak load reductions are responding to transmission rates as opposed to wholesale generation prices. However, they are often viewed as demand response because they are a

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[78] ERCOT, "Load Participation in SCED v1 Overview & Refresher," presented at DSWG Loads in SCEDv1, April 23, 2014.

[79] 555 NPRR-01 070313 Load Resource Participation in Security-Constrained Economic Dispatch, July 3, 2013, online at http://www.ercot.com/mktrules/issues/NPRR555#summary.

[80] Frontier Associates, *2013–2014 Retail Demand Response and Dynamic Project*, Final Report, Public Version, June 23, 2014.

[81] *Ibid.*

form of demand response and because they may occur at approximately the same time that energy prices are high.

IV. Markets with Capacity Obligations

Energy market prices exceed DR strike prices only rarely. Energy market price signals alone may not be sufficient to incentivize a large number of DR providers to enter the market, for example if there are fixed costs of putting in place systems to participate in the market. Markets with capacity obligations are different: they provide reasonably certain availability payments rather than uncertain curtailment payments. While a trend towards higher price caps and more scarcity pricing may lead to increased participation of DR in energy markets in the long run, capacity markets have achieved the highest rates of DR participation up to this point.

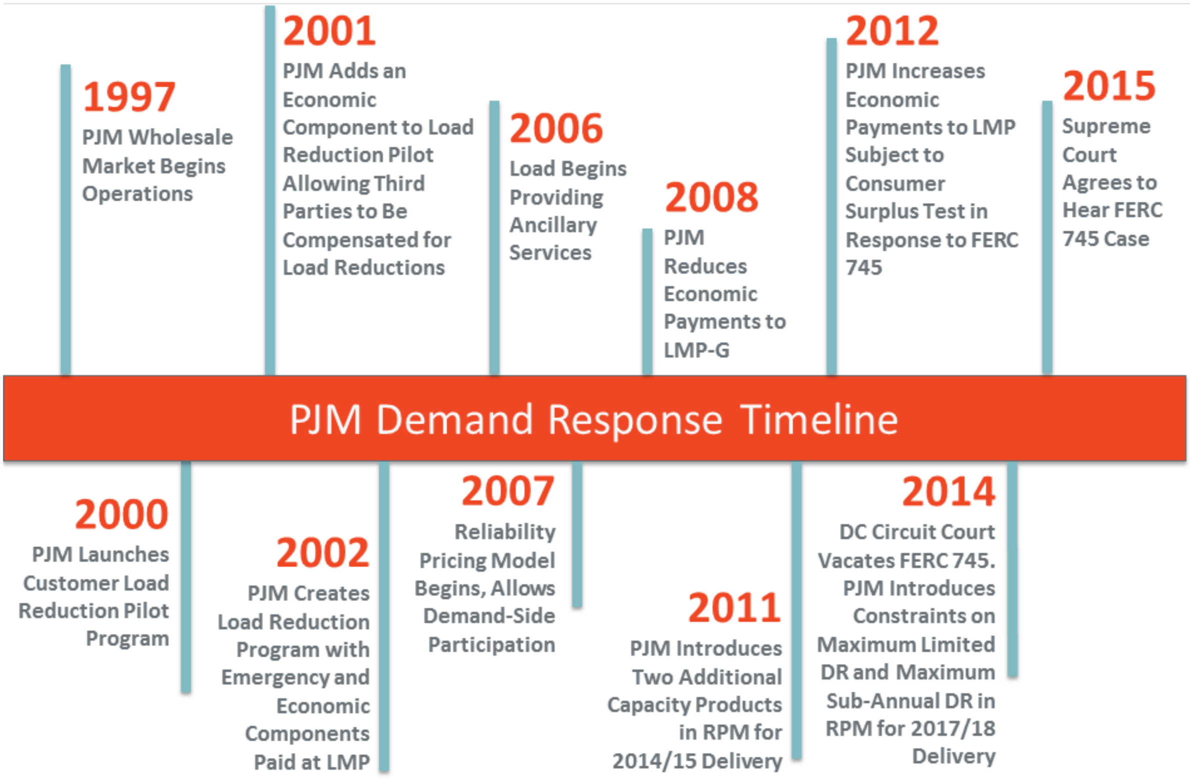
A. PJM Interconnection

The PJM Interconnection began operating its wholesale energy market in 1997. It has included some form of demand participation since a pilot program in 2000 began paying loads for curtailment during emergency conditions. As PJM's market has developed over the last two decades, the ISO has created many additional opportunities for demand to participate in its markets by providing capacity, ancillary services, and energy. In addition to expanding the number of DR programs, PJM has also continuously refined its program rules.

1. Timeline and Status of Demand Response Development

Figure 13 summarizes the history of mechanisms to integrate DR in PJM.

Figure 13
History of Demand Response in PJM



2. Capacity Market Integration

PJM has achieved the most prominent, successful, and rapid development of DR in any US market. Two factors have contributed to PJM's success in procuring DR. First, PJM allowed DR aggregators to participate directly in the market, rather than having to partner with utilities or retailers.[82] (utility DR programs, often conducted in partnership with aggregators, also participate actively in the capacity market). Second, the capacity market attempts to compensate demand resources similarly to generation (Although, as we discuss below, there are important differences between the technical definitions of the capacity services provided by DR and generation). Competing with generation to provide capacity has resulted in a large quantity of DR clearing the capacity markets – with as much as 15,000 MW cleared in the forward capacity auction for the 2015/16 delivery year. Capacity market participation also provides a lot of revenue to DR providers. In PJM, capacity market revenues accounted for 98% of DR revenues in Q1 2015.[83]

PJM's legacy Interruptible Load for Reliability (ILR) program, a holdover from before de-regulation, had always counted towards the reserve margin requirement. When PJM's capacity market (known as the Reliability Pricing Model or RPM) began operating in 2007, demand resources were immediately allowed to participate. The capacity market incorporates a Base Residual Auction (BRA) three years ahead of the delivery year (i.e., the BRA in 2015 procures capacity for 2018/19), followed by three Incremental Auctions as the delivery year approaches. In the initial capacity auctions, demand resources could participate either as ILRs, or through a new program called Emergency DR.

Emergency DR, which curtails load in response to instructions from the system operator rather than in response to price, were required to offer into PJM's capacity auctions in order to receive capacity payments. These resources had either to be certified prior to offering into the auction, or establish credit approximately equal to 30% of "Net CONE" (the administratively determined Cost of New Entry, minus expected energy and ancillary service market revenues) if planning to certify after the auction.[84]

In contrast, ILRs were not required to offer into PJM's capacity auctions. These resources could certify three months in advance of the Delivery Year and receive the final zonal ILR price, determined after the second Incremental Auction.[85] In determining its capacity

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82 "Independent demand response aggregators have a greater financial incentive to sign up as many customers with load reduction capabilities as possible." Synapse Energy Economics Regulatory Assistance Project (RAP), *Demand Response as a Power System Resource: Program Designs, Performance, and Lessons Learned in the United States,* May 2013, pp. 11; "Aggregators have been the source of most new DR and of significant DR innovation in the eastern U.S. RTOs" Pfeifenberger, Johannes and Attila Hajos, Demand Response Review, presented to AESO, March 2011, p. 42

83 Monitoring Analytics LLC, "2015 Quarterly State of the Market Report for PJM: January through March," May 2015.

84 PJM, "PJM Manual 18: PJM Capacity Market," Revision 14, February 23, 2012, p. 33

85 Monitoring Analytics LLC, "2008 State of the Market Report for PJM," March 2009, p. 95.

requirement, PJM assumed that approximately 1,600 MW of ILR would be available on peak in the delivery year. In the 2008/09 delivery year, the first for which this arrangement was in place, more than 3,000 MW of ILR materialized. This was substantially more than the forecasted amount.[86] Furthermore, PJM's 2008/09 forward auction procured far less than 3,000 MW of Emergency DR, presumably because of the requirements to certify or post credit prior to the capacity auction. Had the ILRs been required to participate in the forward auction, the clearing price would likely have been less. In essence, the out-of-market procurement of ILRs may have resulted in excess resources and distorted price formation in the capacity auction.

For the 2012/13 delivery year, DR was fully integrated into PJM's capacity market. As demand resources could no longer earn a capacity payment without offering into the capacity auctions (they had previously been able to do so by registering as ILRs), DR participation in the capacity market increased substantially. The addition of more than 8,000 MW of DR in the capacity market caused a large reduction in the market clearing price, reducing capacity payments to both demand and generation resources.[87] While this outcome had the benefit of incorporating all capacity-based DR resources in the capacity auction, generators subsequently began to oppose further efforts to integrate DR into the capacity market. Procurement of DR in the capacity market peaked in the 2015/16 delivery year at about 15,000 MW, corresponding to 8.5%[88] of PJM's capacity requirement.

At the high and increasing penetration of DR clearing the capacity auctions, PJM identified some potential reliability threats associated with the fact that qualified DR resources can have more limited availability than generation resources. Capacity market rules allowed demand resources to make themselves available only on a subset of hours in the summer, and only for a fixed number of calls whereas generation clearing the capacity market has to be available throughout the year. DR's limited availability did not threaten reliability when DR penetration was low, but at 8.5%, it was displacing a large amount of generation and reducing the generation-only reserve margin. Thus DR was increasingly likely to be called—with a frequency and seasonality outside the bounds of its availability requirements. This led to a higher risk of supply shortfalls, both during the summer and in other seasons.[89]

In order to mitigate this potential reliability problem, PJM defined three separate DR options for the 2014/15 delivery year that it would distinguish from each other and from generation based on availability obligations: Limited DR (continuing current limited availability requirements), as well as Extended Summer DR and Annual DR.[90] PJM then enforced minimum procurement requirements for Annual products (including Annual DR and

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86 Monitoring Analytics LLC, "PJM State of the Market—2008," March 11, 2009, p. 252, http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2008.shtml.

87 James McAnany, "2012 Load Response Activity Report," *PJM Interconnection*, April 2013.

88 Based on a 2015/16 PJM RTO Reliability requirement of 177,184 MW (UCAP).

89 Affidavit of Thomas A. Falin on behalf of PJM Interconnection, Inc., before the Federal Energy Regulatory Commission, Docket No. ER11-___-000, December 2, 2010.

90 PJM, "PJM Manual 18: PJM Capacity Market," Revision 27, January 2015.

generation), as well as a minimum procured amount of Extended Summer + Annual DR. These minimums were intended to increase the overall quality of the demand resources procured through the auction. Higher quality products could continue to receive the same payment as generation; lower quality products could clear at a lower price if the minimum requirements were binding.

- Limited DR is available for interruption during the summer (June-September), on weekdays from noon to 8pm, for up to 10 events per season and 6 hours per event.
- Extended Summer DR is available for an unlimited number of interruptions in the extended summer period of the delivery year. The delivery year runs from June to May, and the summer period is June through October plus May (in the Delivery Year's second calendar year). Interruptions can be called any time from 10am to 10pm, with a maximum 10-hour duration per event.
- Annual DR is available for an unlimited number of interruptions during the Delivery Year, for at least a 10-hour duration per interruption between 10am and 10pm for June to October and the following May, and 6am to 9pm from November to April.

For the 2017/18 Delivery Year, PJM replaced minimums on higher quality DR products with maximums on lower quality products. PJM introduced limits on the quantities of Limited and Extended Summer DR that could be accepted before substantial degradation of reliability might be expected.[91] Limited DR was restricted to 4% of the Peak Load Forecast, "Sub-Annual DR" (the combination of Limited and Extended Summer) was limited to 9%.[92] Total DR remained uncapped, but beyond these limits, DR would have to be Annual. PJM implemented these constraints in its capacity market by paying Limited and Extended Summer resources less than generation in the event that paying it the full price would lead to procuring more than the caps. If procured Limited and Extended Summer DR were less than the caps, it would be paid the same as generation. Annual DR would always be paid the same as generation, as it was not subject to a cap.[93] Essentially, through the steps outlined above PJM was aiming to mitigate the potential reliability impact of Limited and Extended Summer DR by capping the amount procured.

91 PJM, "2017/2018 RPM Base Residual Auction Results," June 2014.

92 *Ibid.*; and "2017/2018 RPM Base Residual Auction Planning Period Parameters."

93 In the 2017/2018 auction there was a price decrement for Limited DR of $13.98/MW-day relative to the clearing price of Extended Summer DR. In most regions, Extended Summer cleared at the same price as Annual resources and generation, with the exception of the PPL area in Pennsylvania, where it cleared at a $66.02/MW-day decrement. (PJM 2017/2018 BRA Results).

Figure 14
DR Participation in PJM Base Residual Auctions and ILR

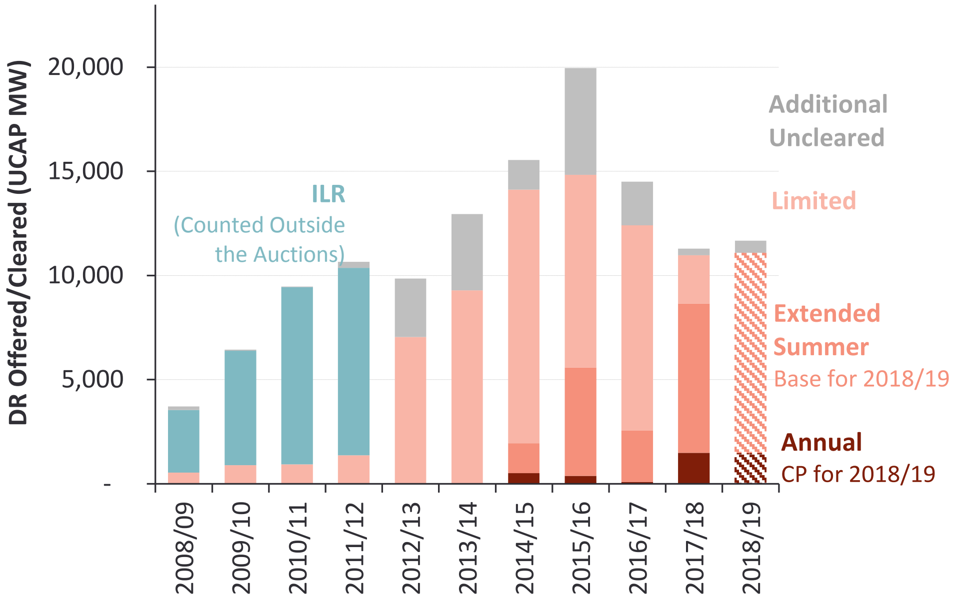

Figure 14 shows a substantial reduction in offered and cleared DR in the Base Residual Auction (BRA) from 2015/16 to 2016/17, with another decline in 2017/18. Note that "Uncleared" resources refer to resources that offered into the capacity auction at a price above the clearing price. Also note that, prior to 2014/15, all DR in the capacity market was effectively Limited DR. There are a number of possible reasons for this decline.

First, if a resource clears in the 3-year forward auction, it has the option of effectively "buying out" its offer in the incremental auction held one year before the delivery year. Clearing prices in PJM's incremental auctions have historically been lower than those in the corresponding forward auction, and PJM was concerned that demand resources in particular were selling in the forward auction and then buying in the incremental auctions, engaging in financial "speculation."[94] It is not clear what feature of the procurement process may have led to this outcome. PJM's market monitor had identified this issue as early as 2012,[95] and in March of 2014, the ISO proposed to amend capacity market rules to penalize providers of capacity that failed to materialize. While the proposal was ultimately rejected by FERC in May of 2014,[96] PJM's consideration of the issue may have dampened DR's participation in the 2016/17 forward auction (held in 2013).

Next, PJM began a stakeholder process in June of 2013 to discuss additional requirements for demand resources in the capacity market. Among the proposals that emerged from the

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94 PJM, Revisions to the PJM Open Access Transmission Tariff and Reliability Assurance Agreement Among Load Serving Entities in the PJM Region to Limit and Protect Against Speculative Offers Submitted in RPM Auctions, before the Federal Energy Regulatory Commission, Docket No. ER14-1461-000, March 10, 2014.

95 Monitoring Analytics, *Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2012*, December 11, 2012.

96 147 FERC 61,108, Order Rejecting Proposed Tariff Changes and Instituting a Section 206 Proceeding, issued May 9, 2014.

stakeholder process was a requirement that DR be required to respond within 30 minutes to an instruction from PJM. Resources had previously had the option to respond within 60 minutes or 120 minutes. Many of these recommendations were filed as a rule change request before FERC in December of 2013.[97] The commission accepted the 30-minute lead-time rule change in a May 2015 order, and the additional requirements may have reduced the amount of DR participation in the capacity market.[98]

Another factor was that PJM tightened the measurement and verification methods for establishing the capacity rating of a DR resource. Whereas PJM originally allowed two methods—one based on "guaranteed load drop" and another based on reducing loads to a "firm service level" when called—it eventually eliminated the guaranteed load drop approach after realizing that some customers who were habitually managing their peak loads were guaranteeing to drop more than all of their forecast peak load. The current approach limits demand reductions to the difference between their so-called "peak load contribution" and their firm service level. This may have sharply reduced participation by some customers.

Finally, the change for the 2017/18 delivery year, establishing a maximum amount of Limited and Extended Summer DR rather than a minimum amount of Extended Summer and Annual DR, effectively increased the requirements for DR clearing the BRA. The 4% cap on Limited Summer DR was less than the cleared amount of Limited Summer in 2016/17. While, the limit on "sub-annual DR" was greater than the cleared amount of sub-annual DR in 2016/17, on the whole it appears that the 2017/18 caps are tighter. In the 2017/18 forward auction, Limited DR cleared at a discount to Extended Summer across the system and Sub-Annual cleared at a discount to Annual in one of thirteen regions. In contrast, in 2016/17, Extended Summer DR cleared with a price adder compared to Limited DR in only two of ten regions and Annual cleared at the same price as Extended Summer everywhere.[99]

3. The Future of DR in PJM

The PJM market is currently facing two major issues which could have a significant impact on the quantity of DR participating in the future. First, *EPSA vs. FERC*, a case which is now being reviewed by the Supreme Court, may affect the way all RTOs, including PJM, compensate DR in energy markets, and possibly in capacity markets as well. We discuss *EPSA vs. FERC* in Section IV.A.4. Second, PJM recently approved a Capacity Performance Proposal that will affect the ability of DR to participate in the capacity market. We discuss the Capacity Performance Proposal here.

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97 PJM, Letter to Honorable Kimberly D. Bose (FERC), re PJM Interconnection L.L.C., Docket No. ER14-822-000, submittal of modifications to the PJM Open Access Tariff, Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. and the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region, December 24, 2013.

98 147 FERC 61,103, Order Rejecting, in Part, and Accepting, in Part, Proposed Tariff Changes, Subject to Conditions, issued May 9, 2014.

99 PJM, "2017/2018 RPM Base Residual Auction Results," June 2014; and PJM, "2016/17 RPM Base Residual Auction Results," May 2013.

Under Capacity Performance, PJM will eliminate the three existing categories of DR (Limited, Extended Summer and Annual), replacing them with two new categories: Base Capacity Demand Resource (BCDR) and Capacity Performance Demand Resource (CPDR). The requirements for Base DR combine requirements for the phased-out Limited and Extended Summer DR programs. Similar to Limited DR, Base DR must be available June through September. Similar to Extended Summer DR, Base DR must be available for an unlimited number of calls up to 10 hours in length from 10 AM–10 PM. Base DR will be allowed to participate in auctions for the 2018/19 and 2019/20 delivery years but will not be allowed to participate thereafter. Capacity Performance DR, which has requirements similar to the phased-out Annual DR product, would be allowed to participate in all future auctions and would be the only product allowed to participate after 2019/20.

In addition to creating these new categories, the Capacity Performance Proposal would limit the procured quantity of Base DR in the 2018/19 and 2019/20 delivery years.

In the short term (2017/18 and 2018/19 delivery years), DR participation may increase because the stringency of Base DR's requirements place it somewhere between the phased-out Limited and Extended Summer DR products which together accounted for the large majority of DR capacity procured in 2017/18, and because the limit on the quantity of Base DR, appears to be higher.[100] After 2019/20 no Base DR will be procured and all DR must be available year round. It seems likely that, as a result, much less DR capacity will participate in PJM's capacity market.

4. Energy Compensation for DR

History of Energy Compensation for DR

Early in the development of its DR programs, PJM paid demand resources an incentive payment through its pilot program. Many US RTOs had similar arrangements to encourage DR to enter energy markets. In 2002, PJM allowed load resources to participate in the wholesale market as DR and receive full LMP (i.e., the regular system price that generators receive) for reductions if the price exceeded a threshold price of $75/MWh. Below the threshold price, DR providers were not paid for load reductions.[101] Then in 2008 PJM reduced the payment to DR providers to "LMP minus G," which is the system price less an amount, "G", representing the savings for the DR provider or the underlying load from not having to procure the energy corresponding to the curtailed volume.[102]

However, in 2011, the Federal Energy Regulatory Commission (FERC) issued Order 745 requiring that all RTOs including PJM should pay full LMP for demand response, but only in

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100 The limits are not strictly comparable because BCDR includes some energy efficiency resources that were not previously included.

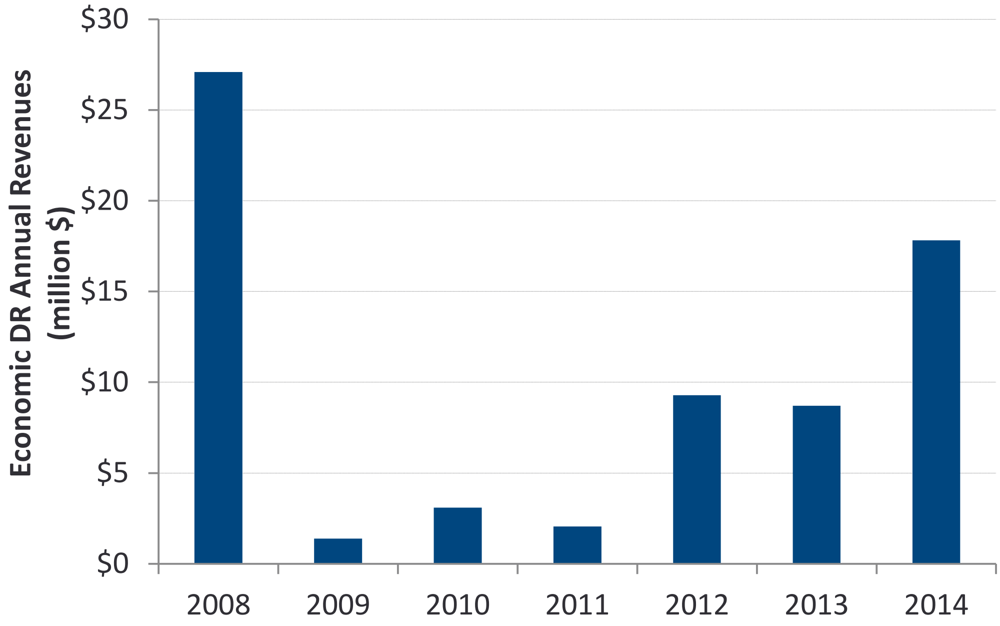
101 Monitoring Analytics, *2013 State of the Market Report for PJM*, Section 6 Demand Response, p. 203.

102 Monitoring Analytics, *2009 State of the Market Report for PJM*, Section 2 Energy Market, Part I.

a subset of hours passing a "net benefits test." PJM and other US RTOs protested the change, but PJM had to comply with FERC's order and switched back to full LMP compensation.

Figure 15 shows the effects of these changes in compensation on annual revenues for participants in PJM's energy market "Economic DR" program from 2008 through 2014 (note that PJM refers to its energy market DR program as "Economic DR"). 2008 was the last year in which DR resources were compensated at LMP and payments exceeded $25 million in that year. In 2009–2011, DR was compensated at LMP-G. At this level of compensation, payments were very low. Since DR strike prices tend to be high compared to average energy prices, DR does not get paid in most periods. In 2012, PJM complied with Order 745 and began compensating DR at full LMP, and compensation increased substantially again.

Figure 15
Energy Market "Economic DR" Annual Revenues



The Electric Power Supply Association (EPSA) sued FERC over Order 745, and a large number of economists supported EPSA's position on compensation.[103] EPSA also challenged whether FERC had jurisdiction over DR, which they claimed was a retail activity within state jurisdiction. The result was that the DC Circuit Court vacated Order 745 in May 2014 on jurisdictional grounds. However, FERC appealed the decision to the US Supreme Court, which agreed to hear FERC's appeal of that decision.[104] That case is still pending.

Without guessing the outcome of the case, we describe below the economic inefficiencies of paying the full LMP to customers for consuming less and "re-selling" energy that they never

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103 Brief of Stanford Economics Professor Charles D. Kolstad as *Amicus Curiae* in Support of Petitioners, in the Supreme Court of the United States, Nos. 14-840 and 14-841, July 16, 2015, p. 10.

104 Orders in Pending Casing, Order List: 575 US, May 4, 2015, available at http://www.supremecourt.gov/orders/courtorders/050415zor_7648.pdf.

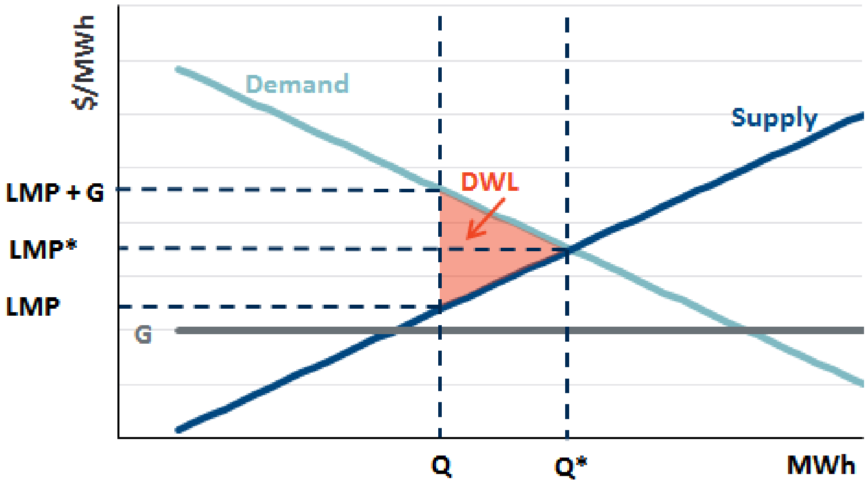
bought in the first place. We also explain the inefficiencies and hazards of FERC's net benefits test.

"Full LMP" vs. "LMP – G" Energy Payments

"Full LMP" refers to a DR provider being paid the same for reducing load as an equivalent quantity of supply provided by a generator in the same location—i.e., the full Locational Marginal Price (LMP). It is understood that in this context that payments to the DR provider are separate from and additional to the corresponding savings made by the associated load customer which, in consequence of a curtailment, consumes and pays for less energy. As a result, a large load whose retail rate is equal to the LMP could in principle receive twice the LMP for curtailing (once for not consuming, thereby cutting its bill by the LMP, and once as a curtailment payment). Those with fixed retail rates would also be overcompensated. Suppose, for example, that a particular load was supplied under a "flat" retail pricing structure and was paying $100/MWh for the energy component of the retail tariff. Much of the time the wholesale price is less than $100/MWh, but sometimes it spikes above $100/MWh. If that load participates as DR and curtails in an hour when the wholesale price is $300/MWh, under "full LMP" there would be a DR payment of $300/MWh and the load would also save $100/MWh on its retail bill, for a net benefit of $400/MWh (more than the corresponding wholesale price). On net, a demand resource paid full LMP therefore effectively "earns" LMP *plus* the value of the curtailed energy, "G". In effect, demand resources paid LMP earn LMP+G. Since a load resource earning LMP+G will curtail consumption or run a backup generator valued above LMP (but below LMP+G), the outcome will be inefficient.

Figure 16 illustrates the effect of load being paid full LMP and thus earning a total of LMP+G for curtailment. In the figure, customers facing real time prices (rather than retail rate G) would consume the efficient level, at Q* at a price of LMP*. However, if load earns LMP+G for curtailment, consumption will be reduced to Q and prices will fall to LMP. The inefficiency resulting from this change is illustrated as the red shaded area labelled Deadweight Loss (DWL) in the figure.

Figure 16
RTP vs. LMP - G



The alternative policy of paying the DR provider "LMP minus G" refers to the payment to the DR provider being reduced by the amount of the corresponding underlying energy procurement savings (and under "LMP minus G" the notional large load paying LMP would receive LMP-LMP, i.e., zero, as an incentive payment, but would still reduce its bill by LMP in an hour where it curtailed). In the example above, a payment of "LMP minus G" would give the DR $200/MWh, for a net benefit of $300/MWh. This would provide efficient price signals for the end user to reduce its consumption or run a backup generator, since the effective price would be the same as the wholesale price.[105]

However, even "LMP-G" is imperfect if the customer is actually shifting its consumption rather than eliminating it. For shifted consumption, the right compensation would be the difference in LMPs between the two hours. Furthermore, LMP-G is somewhat challenging to administer because it requires determining the relevant rate for end-users or an aggregation thereof. PJM and MISO has both developed practical ways to do this.

FERC's Net Benefits Test

Figure 17 illustrates the structure of FERC's net benefit test.[106] When DR is activated, the total electricity consumed is reduced (by ΔQ, from Q^{H} to Q^{DR} in the figure), resulting in a drop in prices (of ΔLMP, from LMP^{H} to LMP^{DR} in the figure). Under the test, full LMP would be paid to DR only when the reductions in total customer payments associated with DR exceeded the payments to resources. Payments would be made when $\Delta LMP \times Q^{DR} > LMP \times \Delta Q$. The net benefits test is designed to ensure that the total savings to all consumers from the reduction in wholesale prices exceeds the corresponding payments to the DR providers, so that consumers might see a net benefit.

However, this test is blind to producer costs and revenues and thus does not improve total social surplus or reduce total resource costs. Nor does it account for the effect of generators' responses to reduced prices. Generators can be expected to correspondingly increase their capacity market offers (where relevant) and/or exit the market—and in the long run, the combined payments of consumers in the capacity and energy markets will have to rise to the cost of new generation entry, with or without demand response. Suppliers are also likely to perceive high regulatory risks in markets that pursue price-suppressing policies (as implied by a price-suppression test for justifying subsidies to DR), thus raising the cost of investing. In the long term, subsidizing uneconomic activity and undermining market participation is likely to hurt consumers as well as producers.

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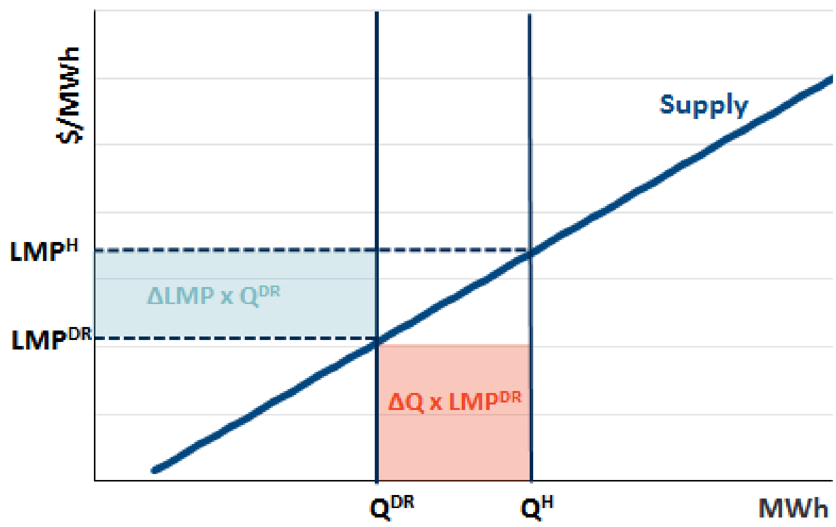
105 Comments of Samuel Newell, Kathleen Spees and Philip Q Hanser, before the Federal Energy Regulatory Commission, Docket No. RM10-17-000, filed in response to August 10, 2010 Supplemental Notice of Proposed Rulemaking and September 13, 2010 Technical Conference regarding the wholesale compensation of demand response providers, October 5, 2010.

106 PJM, *FERC Order 745: The Net Benefits Test*, 2011.

Figure 17
Illustration of FERC's Net Benefits Test



5. Energy Market Pricing and Dispatch

PJM allows DR to participate in day ahead and real time energy markets. In 2014, of the approximately 9,000 nominated MW in the RPM, less than 2,000 MW were also registered to participate in the energy market under the energy market "Economic DR" program.[107] Despite the possibility of payments at full LMP, participation in the energy market program remains low. This low participation is likely due to the fact that the energy market program is so much less lucrative than the emergency program. In 2014, the emergency program accounted for nearly 97% of payments to DR providers, compared to 2.5% for the energy market program and 0.7% for synchronized reserves.

PJM's emergency and ancillary service DR products are dispatched outside of the market. In other words, emergency and ancillary services DR were not responding to the energy price when being curtailed, nor were they directly setting the price in times when they were curtailed. While deployment of these products helped the ISO recover from contingency or emergency situations, activating these resources reduced load and could lead to reductions in energy prices during times of scarcity.

In order to address this situation, and partly to respond to FERC Order 719,[108] PJM enhanced its scarcity pricing mechanism by having DR also submit an hourly energy strike price. Unlike the offers submitted under the energy market "Economic DR" program, where

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[107] Monitoring Analytics, *2014 State of the Market Report for PJM: Volume 2: Detailed Analysis*, Section 6 Demand Response, March 12, 2015.

[108] US RTOs have all implemented administrative scarcity pricing mechanisms to increase prices during shortage conditions, especially during Operating Reserve shortages. FERC Order 719 required all RTOs to implement these mechanisms. This has resulted in higher price caps and more frequent price spikes. Such spikes are important to properly incent price-responsive load.

available MW and strike price can be updated hourly, emergency strike prices are fixed. Emergency strike prices tend to be higher than energy market strike prices.[109]

Under PJM's updated rules, DR is curtailed/triggered when prices exceed the strike price, as well as in response to non-price emergency event triggers. In the event of curtailment using a non-price trigger, DR will still be called from lowest to highest strike price. Additionally, energy prices will still be set by the strike price of the called DR.

Having implemented these changes relatively recently, PJM does not have a lot of experience with the new regime. However, the overall effect of the program should be to correct for price suppression when emergency DR is called and contribute to (appropriately) higher and more volatile prices in the energy market. As we discussed earlier, higher and more volatile prices tend to create an incentive for more DR to participate in energy markets.

B. ISO New England

ISO New England (ISO-NE) was formed in 1997 as part of the general movement towards electricity deregulation during the mid-1990s. ISO-NE's geographical footprint consists of the six states that comprise New England: Maine, Vermont, New Hampshire, Massachusetts, Connecticut, and Rhode Island. Its wholesale power markets were launched in 1999 to include day-ahead and real-time dispatch that support competitive wholesale and retail pricing.

Similar to PJM, ISO-NE's wholesale power system can be categorized into three markets with various products: Energy, Capacity, and Ancillary Services. The energy markets operate under both hourly day-ahead and five-minute real-time locational marginal prices (LMPs) in a roughly 1,000 node system. Offer prices are capped at $1,000/MWh, but energy prices can reach as high as $4,050/MWh when reserve constraints are violated under scarcity conditions. The vast majority of resources that participate in ISO-NE's energy market also participate in its annual forward capacity market held three years in advance of each commitment period. DR resources in ISO-NE are allowed to participate in the energy and forward capacity markets, provided that the resources meet certain minimum qualification requirements. Inclusion of demand response in ISO-NE's ancillary service market is scheduled for June 2017, when ISO-NE plans to fully integrate demand response into its wholesale markets, complying with FERC Order 745.[110]

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109 Monitoring Analytics LLC, (2015). "Quarterly State of the Market Report for PJM: January through March, Section 6: Demand Response," May 2015. Posted at http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2015/2015q1-som-pjm-sec6.pdf

110 ISO-NE recently announced a proposal to delay the full integration of demand response resources into the energy and reserves markets by one year to June 2018 due to the pending Supreme Court decision of FERC Order 745. See Yoshimura, Henry (ISO New England) to NEPOOL Committee re "Proposed Tariff and Manual Changes to Delay the Full Integration of Demand Response into the Wholesale Markets by One Year," July 1, 2015, available at http://www.iso-ne.com/static-assets/documents/2015/07/a07_iso_memo_07_01_15.docx.

1. Timeline and Status of Demand Response Development

Demand response in ISO-NE dates back to 2001 when the ISO first incorporated DR into its wholesale markets through the 'Load Response Program' (LRP). The LRP consisted of two real-time programs: the 'Demand Response Program' and the 'Price Response Program'. Customers who were enrolled in the Demand Response Program received mandatory load reduction notifications dispatched by the ISO and were obligated to reduce load within 30 minutes of receiving the ISO's instructions. The Price Response Program allowed resources to decide whether to curtail load if the energy clearing price was greater than or equal to $100/MWh. The Price Response Program accounted for the majority of demand response resources participating in the LRP.

In 2003, ISO-NE redesigned its energy markets with bid-based day-ahead and real-time markets as part of the Standard Market Design (SMD) overhaul. Under SMD, ISO-NE launched three new demand response programs:

- *Real-Time Two-Hour Demand Response*: Similar to the 30 minute program under the LRP, the two-hour demand response program provided customers with a longer, two-hour notice period to respond to ISO instructions. DR providers were paid the greater of $100/MWh or the real-time LMP.
- *Real-Time Profiled Response:* DR eligibility was extended to customers with direct load control technology but not necessarily with interval metering under a demand response aggregator. Response was determined by estimating the baseline consumption based on load profiles and DR providers were paid the greater of $100/MWh or the real-time LMP.
- *Day-Ahead Load Response (DALRP)*: DR providers were allowed to participate in the day-ahead market, directly competing with traditional supply offers.[111]

ISO-NE maintained the two pre-SMD real-time programs under the LRP, renaming them *Real-Time 30-minute Demand Response* and *Real-Time Price Response (RTPR)*. These five programs remained in effect until 2010, which marked the first commitment period for resources purchased through ISO-NE's newly established Forward Capacity Market (FCM). Significant changes to the structure of ISO-NE's demand response programs accompanied ISO-NE's transition to the Forward Capacity Market. ISO-NE extended only two of the five pre-FCM programs to 2012—the RTPR and the DALRP—while the other three reliability programs were retired at the start of the 2010 Forward Capacity Market commitment period.

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[111] The Day-Ahead Load Response Program was implemented in 2005, a few years later than the other two DR programs launched under SMD.
ISO New England, "2003 Annual Markets Report," 2004, available at http://www.iso-ne.com/static-assets/documents/markets/mkt_anlys_rpts/annl_mkt_rpts/2003/2003_Annual_Markets_Report_Final.pdf.
ISO New England, "2005 Annual Markets Report," June 1, 2006, available at http://www.iso-ne.com/static-assets/documents/markets/mkt_anlys_rpts/annl_mkt_rpts/2005/2005_annual_markets_report.pdf.

ISO-NE defined two broad categories of demand resources eligible to receive capacity payments in the FCM: *active demand resources* and *passive demand resources*. Dispatchable resources fall under the "active" demand response category and represent traditional DR resources required to respond to ISO dispatch instructions.[112] ISO-NE created two new DR programs in the FCM for active demand resources. Capacity payments to these resources are calculated by the amount of capacity a demand resource clears in the FCM multiplied by the FCM clearing price. These FCM programs are still in effect today and are summarized in Table 4, along with ISO-NE's other recent DR programs.

Table 4
Summary of Recent ISO-NE Demand Response Programs

Program	DALRP	Action	Purpose	Payments	Description
Forward Capacity Market Programs (Existing)					
Real-Time Demand Response (RTDR)	Yes	Dispatchable	Reliability	Capacity Clearing Price x Clearing Quantity (plus any Energy Market Performance priced at LMP)	Participants must curtail load within 30 minutes of dispatch instruction
Real-Time Emergency Generation (RTEG)	No	Dispatchable with limits	Reliability	Capacity Clearing Price x Clearing Quantity (plus any Energy Market Performance priced at LMP)	Distributed generation the ISO calls on during a 5% load reduction which requires more than 10 minutes to implement. Operation limited to 600 MW.
Pre-FCM programs (Retired)					
Real-Time Profiled Response	Yes	Dispatchable	Reliability	Greater of $100/MWh or LMP	Retired May 2010. Customers had individual load control but no individual metering. ISO instead relied on statistical measurements.
Real-Time Two-Hour Demand Response	Yes	Dispatchable	Reliability	Greater of $350/MWh or LMP	Retired May 2010, Loads must interrupt within two hours of ISO instructions
Real-Time 30-Minute Demand Response	Yes	Dispatchable	Reliability	Greater of $500/MWh or LMP	Retired May 2010, Loads must interrupt within 30 minutes of ISO instructions
Energy Market Programs (Existed Until June 1, 2012)					
Real-Time Price Response (RTPR)	Yes	Voluntary	Economic	Greater of $100/MWh or LMP	When day-ahead or hourly real-time forecast LMP is greater than or equal to $100/MWh, the ISO may open the eligibility period and loads may bid in.
Day-Ahead Load-Response Program (DALRP)	The DALRP is open to RTPR and RTDR loads. Loads receive no additional payments beyond energy market payment. The voluntary program is designed to increase system reliability by allowing loads to receive the real-time LMP for load reductions during hours when the asset clears in the day-ahead market.				

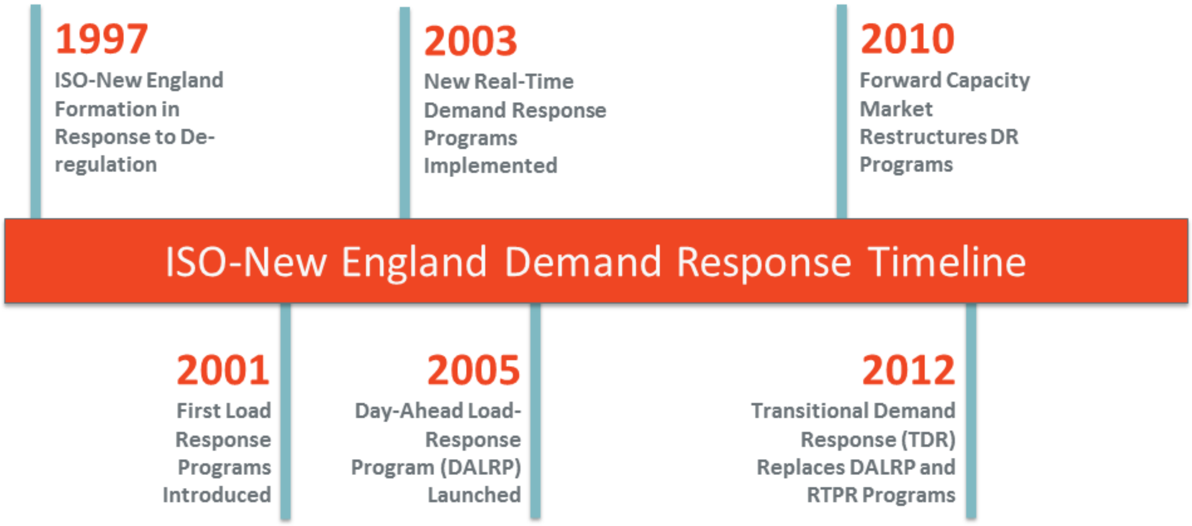
Source: Adapted from an ISO New England presentation, *Introduction to Demand Response in ISO-NE Markets*, May, 2015 and ISO New England's Internal Market Monitor report, *2010 Annual Markets Report,* p. 90. Included data from ISO New England, "2005 Annual Market Report," June 1, 2006, p. 107.

In 2012, ISO-NE retired the two price-responsive energy market programs included at the bottom of Table 4 and replaced them with a new energy market program called the *Transitional Price-Responsive Demand (TPRD) Program*. This program was in many ways

[112] Demand resources that reduce electricity consumption across many hours, such as through energy efficiency and similar measures, fall under the "passive" demand resource category.

similar to the two prior energy market programs, except that it contained a few mandatory changes in order to comply with the FERC Order 745 ruling on demand response compensation in wholesale markets. Note that these programs are dispatchable by the system operator. As the name suggests, the TPRD Program is intended to serve as a temporary program until ISO-NE fully integrates demand response into all aspects of its wholesale markets, including the incorporation of DR into ISO-NE's real-time and forward reserves markets. Figure 18 provides a timeline highlighting the key developments in ISO-NE's evolution of demand response since ISO-NE's inception in 1997.

Figure 18
History of Demand Response in ISO-New England

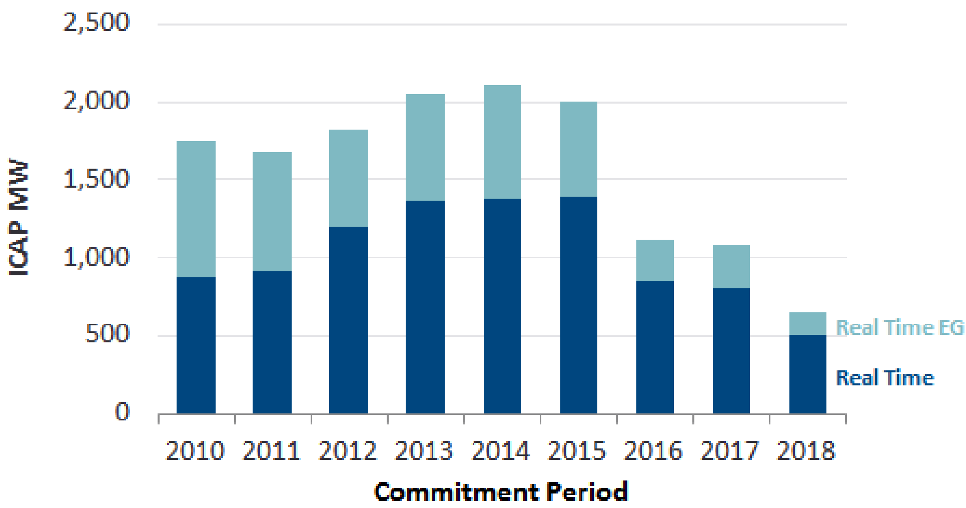


2. Capacity Market Integration and Recent Decline in Participation

ISO-NE's first Forward Capacity Market auction was held in 2007 three years in advance of the June, 2010 through May, 2011 commitment period. As mentioned in Section IV.B.1, ISO-NE administers two demand response programs to attract active demand resources through its FCM: *Real-Time Demand Response (RTDR)* and *Real-Time Emergency Generation (RTEG)*. RTDR resources reduce load within 30 minutes of receiving an ISO dispatch signal, whereas RTEG resources reduce load by shifting load from the electricity grid to local emergency generators. Demand resources in the FCM are treated like traditional generation resources; resources that clear take on a capacity supply obligation (CSO) and receive capacity payments determined by the FCM clearing price.

As shown in Figure 19, the level of DR clearing in ISO-NE's FCM has declined in recent years. We do not have a definitive explanation for the steep decline in participation, but we understand that at least four factors may have contributed: (1) Prior to 2016/17 (FCA7), there was a price floor of approximately \$3/kW-month artificially supporting the price in forward auctions, but not in shorter-term reconfiguration auctions. This allowed DR providers to offer planned resources in the forward auctions at low risk, since they could likely buy out of their obligation at lower prices later (but lose their financial security deposit associated with the planned resources).[113] (2) ISO-NE changed its rules to increase the granularity of any aggregations to 19 separate dispatch zones. This made it harder to diversify resource development and performance over a portfolio of existing and planned assets. (3) We have heard from market participants that ISO-NE's M&V protocols could expose them to cumbersome compliance proceedings. And (4), starting in 2018/19, the newly introduced Pay-for-Performance incentives/penalties added more risk, since taking on a capacity supply obligation would expose capacity providers to a short position in "performance" at a rate of $2,545/MWh whenever the system experiences scarcity conditions. This applies to all types of resources but may be especially daunting for demand response resources who may be uncertain about their ability to reduce load during any given scarcity event.

Figure 19
ISO New England Forward Capacity Auction Cleared Demand Response



Sources and notes: Data from ISO New England, "Forward Capacity Auction Total Flows Diagram" for each capacity auction. See http://www.iso-ne.com/markets-operations/markets/forward-capacity-market. The commitment period begins in June of the year shown and finishes at the end of May the following year.

3. Challenges in Establishing Demand Response Baselines for Energy

A fundamental feature of many DR programs with participation on the supply side[114] is the baseline methodology used to calculate performance and payments. Baselines are intended to

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[113] From a more cynical perspective, a supplier could exaggerate its planned resources in the forward auction and plan to buy out of its obligation later as a way to arbitrage the expected difference between forward auctions and shorter-term reconfiguration auctions. But this would not have been a risk-free strategy, and it would not have been a sustainable business model for aggregators that wanted to develop physical assets and wanted ISO-NE to believe its development plans for future auctions.

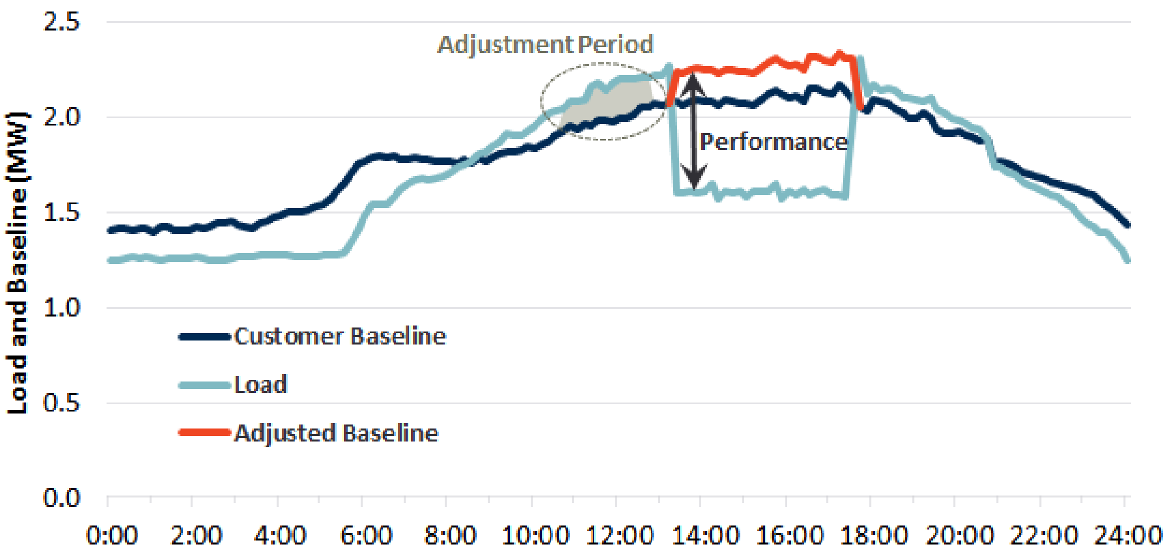
[114] As distinct from participation as a scheduled load, where a demand curve would be bid. Some DR programs (*e.g.,* Singapore's proposed program) effectively require DR providers to bid on the demand side (although in the Singapore case the DR resource bids an absolute quantity of load and

Continued on next page

reflect the hypothetical, "business-as-usual" load a resource would have consumed had it not implemented load reduction measures. Without a baseline, system operators would have no reasonable way of measuring a resource's change in load and determining its compensation for curtailment.

A variety of baseline methodologies have been implemented across markets, each with their own pros and cons. The two broad methods for estimating baselines are a 'customer baseline' (CBL) approach and a "firm service level" (FSL) approach. ISO-NE is an example of a market that uses the CBL approach. To establish an initial baseline for a new DR participant, ISO-NE records metered load data in five-minute intervals from the initial 10, non-demand response holiday weekdays and averages each corresponding interval across the 10 days. Once the initial baseline is set, ISO-NE subsequently calculates updated baselines daily by performing a 90/10 weighted average, with a 90% weighting applied to the historical baseline from the prior day and a 10% weighting applied to the prior day's actual metered load. In the event that a demand response resource curtails load, ISO-NE performs a final 'baseline adjustment', in which the baseline is scaled up or down according to a single adjustment factor. The adjustment factor shifts the baseline to a level consistent with a resource's load in the immediate hours leading up to the DR event by calculating the average difference between the resource's actual load and the baseline. Figure 20 highlights the two hour window containing the five-minute intervals included in the adjustment factor calculation and illustrates the difference between the adjusted, final baseline and the unadjusted baseline.

Figure 20
Example of Demand Response Performance and Baseline Adjustment



Source: Adapted from an ISO New England presentation, *Introduction to Demand Response in ISO-NE Markets*, May, 2015.

Continued from previous page

an absolute quantity of load reduction, together with a supply price for the reduction (not a demand price for the reduced load)).

The CBL approach is the most common among current demand response programs, as it incorporates a resource's metered load from the most recent days leading up to an interruptible event and constructs a baseline consistent with that resource's latest consumption patterns. The firm service level approach, on the other hand, offers a simpler, more static, way to develop a baseline by taking a simple average of a resource's previous seasonal peak monthly demand. While the firm service level methodology offers added simplicity and transparency, thereby allowing stakeholders to more easily analyse and validate performance themselves, it has the downside that a facility's baseline does not reflect its recent metered consumption (because it does not have the "adjustment" of the CBL) and it lacks the granularity of a customer baseline.

An inherent challenge in establishing an accurate demand response baseline is preventing opportunities for 'gaming' or manipulation. DR participants may have an incentive to try to increase their baselines because the payment they will receive is proportional to the difference between the baseline and actual metered load. In the case of Lincoln Paper and Tissue LLC, a paper mill in Maine, FERC determined that Lincoln increased its baseline by reducing its use of on-site generation during the initial baseline period and instead drawing additional power from the grid. Lincoln then offered demand response into ISO-NE's DALRP on a daily basis at the minimum offer price, which almost always cleared in the market, and replaced the artificially high level of power it had pulled from the grid during its initial baseline period with power from its on-site generator. FERC found that Lincoln had violated the Commission's regulations and provisions of the Federal Power Act which prohibit energy market manipulation, and directed Lincoln to pay a $5 million civil penalty and disgorgement of over $0.3m, plus interest.[115]

Another example involves the Baltimore Orioles baseball stadium in Maryland. Enerwise Global Technologies, a demand response service provider participating on behalf of the Maryland Stadium Authority, reached a settlement with FERC after an investigation into allegations that Enerwise attempted to achieve artificial baseline inflations at the stadium. The Orioles stadium lighting was turned on after PJM declared an emergency event scheduled to start two hours later, even though no baseball game was played that evening, thereby increasing its load in the pre-event hours and potentially increasing the baseline that could have been used to assess DR during the emergency event.[116] This case settled with Enerwise agreeing to pay a civil penalty of $780,000 and disgorgement of $20,726 plus interest.

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[115] 144 FERC ¶ 61,162, Order Assessing Civil Penalty, issued August 29, 2013, available at https://www.ferc.gov/enforcement/civil-penalties/actions/144FERC61162.pdf.

[116] 143 FERC ¶ 61,218, Order Approving Stipulation and Consent Agreement, issued June 2013, available at http://www.ferc.gov/enforcement/civil-penalties/actions/143FERC61218.pdf.
The Office of Enforcement also determined that Enerwise committed to 4.6 MWs of load reduction, which relied on simultaneous operation of an ice-storage facility and two 1.8 MW on-site generators, all of which could not operate concurrently without causing the generators to trip off-line. Thus registering 4.6 MW was an unrealistic reflection of routine operation levels.

Irrespective of attempts to increase the baseline, establishing accurate demand response baselines can be challenging in any case due to natural factors, such as weather uncertainty, changing business practices, and other fluctuations in load during an event. While no perfect solution exists to completely address the challenges of establishing demand response baselines, some markets are considering, or have recently implemented, baseline methodologies rooted in statistical regressions. For example, the French utility company Électricité de France (EDF) is currently experimenting with data intensive methods to estimate baselines in its ongoing Smart Electric Lyon (SEL) project. This project utilizes smart meters to gather granular load data that can be used to estimate a control group's baseline and impact of demand response. Using regression modelling, an individual resource's baseline can be calculated more accurately by constructing a control group that captures certain complexities, such as the variable weather component of load.[117] While the regression approach attracts appeal in its sophistication and precision, notable downsides include less transparency, added complexity, and in certain cases an inability to formulate a baseline until *after* the interruptible event has concluded, preventing market participants from understanding their demand response performance in real-time.

C. Ontario

Ontario's electricity restructuring process began in the late 90s with government committees and reports discussing the breakup of Ontario Hydro, the Province's traditional vertically integrated utility. The Ontario electricity market opened in May of 2002. Though Ontario does not have a formal capacity market, long term capacity commitments are procured through contracts between generation owners and the Independent Electricity System Operator (IESO). Ontario's restructured electricity sector originally included another entity, the Ontario Power Authority (OPA), which was responsible for long-term planning and ensuring resource adequacy. Prior to the merger between the IESO and the OPA in early 2015, the latter organization was the contracting entity.

1. Timeline and Status of Demand Response Developments

From its inception, Ontario's 5-minute energy market included the possibility (but not the requirement) of demand-side bidding in the energy market and the provision of operating reserves by load.[118] Most participants were large loads purchasing wholesale electricity and included no payment above the avoided cost of reduced consumption.[119] The active participation of load in the market clearing process afforded advantages over simple price-

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[117] Hatton, Leslie, Philippe Charpentier, and Eric Matzner-Lober. "Online Residential Demand Reduction Estimation Through Control Group Selection," Chapter 8, *Modeling and Stochastic Learning for Forecasting in High Dimensions*, A. Antoniadis, et al. (Eds.), Vol 217. (Switzerland: Springer International Publishing, 2015).

[118] Ontario Energy Board, *Market Surveillance Panel Monitoring Report on the IESO-Administered Electricity Markets for the period from May 2006–October 2006*, Public, December 13, 2006, p. 130.

[119] However, loads have an incentive to bid because only loads that bid are eligible to provide reserves in the AS market (see *Quick Takes: Dispatchable Loads*, IESO, revised January 31 2012).

responsive load. All wholesale loads in Ontario pay the Hourly Ontario Electricity Price (HOEP), plus the GA uplift (discussed below), rather than nodal or zonal prices paid to generators. As a result, the incentive for price-responsive load does not entirely align with the benefits of such curtailment. By scheduling the curtailment of loads, the IESO could achieve a more efficient schedule than by relying on loads to self-curtail.

In 2003, the IESO introduced the Hour Ahead Dispatchable Load Program. This program aimed to allow loads unable to respond to a 5-minute dispatch signal to actively participate in markets. Loads participating in the program submitted bids to the three hour-ahead pre-dispatch process and were dispatched to curtail if the pre-dispatch price exceeded their strike price. Loads were made whole (by paying them the difference between their bid price and the HOEP) if the real time price ended up being less than the strike price.[120] In the same year, the IESO introduced the Transitional Demand Response Program (TDRP). Program participants had the option to voluntarily curtail when the 3 hour-ahead price exceeded a threshold of $120/MWh and would be paid the pre-dispatch price for this curtailment, up to a maximum of $500/MWh.[121]

In 2005, OPA initiated the DR1 program (OPA was the capacity contracting entity prior to the IESO/OPA merger in 2015). This program was similar to IESO's TDRP program, though participants submitted their own strike price rather than responding to a single strike price. Participants would be paid their strike price (rather than the pre-dispatch price as they had under TDRP) for curtailment. Additionally, the program was not integrated into the IESO's dispatch process, leading to the potential for inaccurate scheduling of imports.[122] In 2006, IESO initiated an emergency DR program—the Emergency Load Reduction Program (ELRP). Under the ELRP, the IESO notified participants the day before or the morning of a day when ELRP would be implemented. ELRP would be implemented on days when the IESO projected a risk of an emergency situation. Registered loads submitted offers to curtail in the event of an emergency occurring over the course of the day. Cleared participants received a standby payment (originally $15/MW-h). Actual curtailments were paid at a pre-arranged price (originally $400–$600/MWh depending on duration of curtailment).[123]

Also in 2006, the Provincial government issued a Supply Mix Directive to the OPA setting new targets for demand side participation. In response, the OPA created a number of new programs attempting to encourage demand side participation in many areas of the market. Under the DR3 program, initiated in 2008, OPA executed multi-year contracts with demand resources for their curtailment capacity. The program required that participants be available for curtailment by the system operator for 100 or 200 activations of four hours or less per year (though actual activation rates are far below these thresholds). Under the DR3 contracts,

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120 *Ibid.*, p. 132

121 Ontario Energy Board, *Market Surveillance Panel Monitoring Report on the IESO-Administered Electricity Markets for the period from November 2005–April 2006*, Public, June 14, 2006.

122 Ontario Energy Board, *Market Surveillance Panel Monitoring Report on the IESO-Administered Electricity Markets for the period from May 2009–October 2009*, Public, January 29, 2010, p. 50

123 Independent Electricity System Operator (IESO), *Guide to the Emergency Load Reduction Program*, Marketplace Training, Public, June 27, 2006.

OPA paid participants for their availability in addition to paying them $200/MWh for the curtailment itself. The goal of the program was to reduce the need for generation capacity on peak and the program's structure is broadly comparable to capacity market DR programs in US capacity markets.[124] Under another contractual program, DR2, participants agreed to shift their use from peak hours to off-peak hours throughout the year.[125]

More recently, IESO (recently merged with OPA) began a process of transitioning towards an auction structure for procuring DR capacity commitments. An industry stakeholder group has contributed to the market re-design process, which aims to hold its first demand response auction in 2015 for delivery in 2016. IESO has also initiated a DR Pilot Program to encourage more active participation of loads in 5-minute and hourly load following as well as unit commitment.

Figure 21
History of Demand Response in Ontario

2. Contract programs and the Industrial Conservation Initiative

In addition to the Hourly Ontario Electricity Price (HOEP), wholesale customers in Ontario also pay the Global Adjustment (GA). The GA, introduced in 2005, covers (among other things) the cost of meeting the capacity target. As of the end of 2013, the GA substantially exceeded the HOEP, with loads therefore paying more than twice the HOEP for each MWh consumed.

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124 Ontario Energy Board, *Market Surveillance Panel Monitoring Report on the IESO-Administered Electricity Markets for the period from May 2009–October 2009*, Public, January 29, 2010, p. 52

125 DR2 was introduced after DR3. DR2 was a non-event based peak shifting program with low enrolment that has been canceled.

The GA is collected from large wholesale customers (those with monthly peak loads in excess of 5 MW or on an opt-in basis for those in excess of 3 MW) proportional to their consumption on the Province's five peak hours of the year. These customers have an incentive to anticipate these peaks and reduce their consumption in order to reduce their share of the GA payment.[126] This process for recovering the GA is known as the Industrial Conservation Initiative and the IESO has estimated that it contributes to 850 MW of peak reduction.[127]

Large industrial loads participating in the ICI may also be participating in OPA/IESO's contract-based DR programs. OPA's DR3 program, and the transitional program that has recently taken its place, pay participants both for their availability for curtailment on-peak. Since contractual DR activation is based on the supply cushion (the amount of total supply minus demand) and the HOEP, there is a good chance that activations will occur during periods where ICI customers were already planning to curtail. In fact, Ontario's market monitor reported that DR3 was activated during one of the five peak hours in the summer of 2015.[128]

3. Summer and Winter Demand Response Capacity Auctions

In its 2013 Long Term Energy Plan, the Province determined that responsibility for meeting demand response targets would be transferred from the Ontario Power Authority (OPA) to the IESO. In response, the IESO proposed first to transfer participants in the OPA's contract-based DR programs ("DR2" and "DR3") to a Capacity Based Demand Response Program, and then to conduct DR auctions.[129] Under current arrangements, both DR and generation capacity are for the most part procured under contract with the IESO. The proposed DR auction would consolidate procurement of DR into a single auction. The DR auction is seen as a stepping stone towards a full capacity auction, where DR and generation procurement would presumably happen in parallel.

Through the auction process, the IESO aims to procure approximately the same amount of DR as was formerly participating in OPA's contractual programs.[130] The organization has proposed that DR will be procured using a sloped rather than vertical demand curve, so the precise amount of cleared DR is difficult to predict.[131] The IESO hopes that the DR auctions

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126 Note that the GA must still be recovered in aggregate—the burden is simply shifted onto other large customers who do not curtail and smaller customers.

127 IESO, "Comparison of 2013 Long-Term Energy Plan to 2013 Actual Results," June 2015.

128 Ontario Energy Board, *Market Surveillance Panel Monitoring Report on the IESO-Administered Electricity Markets for the period from May 2011–October 2011*, Public, April 25, 2012,, p. 70

129 Chiarelli, Bob (Ministry of Energy) to Bruce Campbell (IESO) re Encouraging Development of DR, March 31, 2014.

130 IESO, DR Auction MW Requirement, presented at DR Auction Stakeholder Meeting #1, October 1, 2014.

131 IESO, DR Auction Mechanics, presented at DR Auction Stakeholder Engagement Meeting #2, October 20, 2014, p. 6.

will help to secure demand response at the lowest possible cost and provide a stepping stone in the development of full capacity markets.[132]

The IESO hopes to conduct the first auction in 2015 for delivery in 2016. Going forward, however, the operator will procure (with different clearing prices) resources available in the summer and winter seasons, conducting annual auctions five months in advance of the summer delivery season.[133] The proposed design will require cleared DR resources to offer energy market bids during their availability window. These resources will be required to have their commitment status determined by the day-ahead commitment process[134] The auction process will be locational, in the sense that upper bounds will be placed on the quantity of DR resource procured in each zone.[135]

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132 IESO, *DR Auction Market Design Document*, Issue 2.0, Public, April 10, 2015, p. 5.

133 *Ibid.*, p. 7

134 Note that though Ontario conducts a day-ahead commitment process in order to ensure sufficient online capacity, the Province lacks a day-ahead *market* where electricity can be transacted.

135 IESO, *Market Manual 12: Capacity Auction, Part 12.0 Demand Response Auction*, Issue 0.1, Public, MAN-44, effective September 30, 2015, p. 14.

V. Key Observations

In sections I through IV above we described the evolution of DR mechanisms in six wholesale markets. In this section we draw out some themes and key observations.

A. Routes for Demand Response Participation

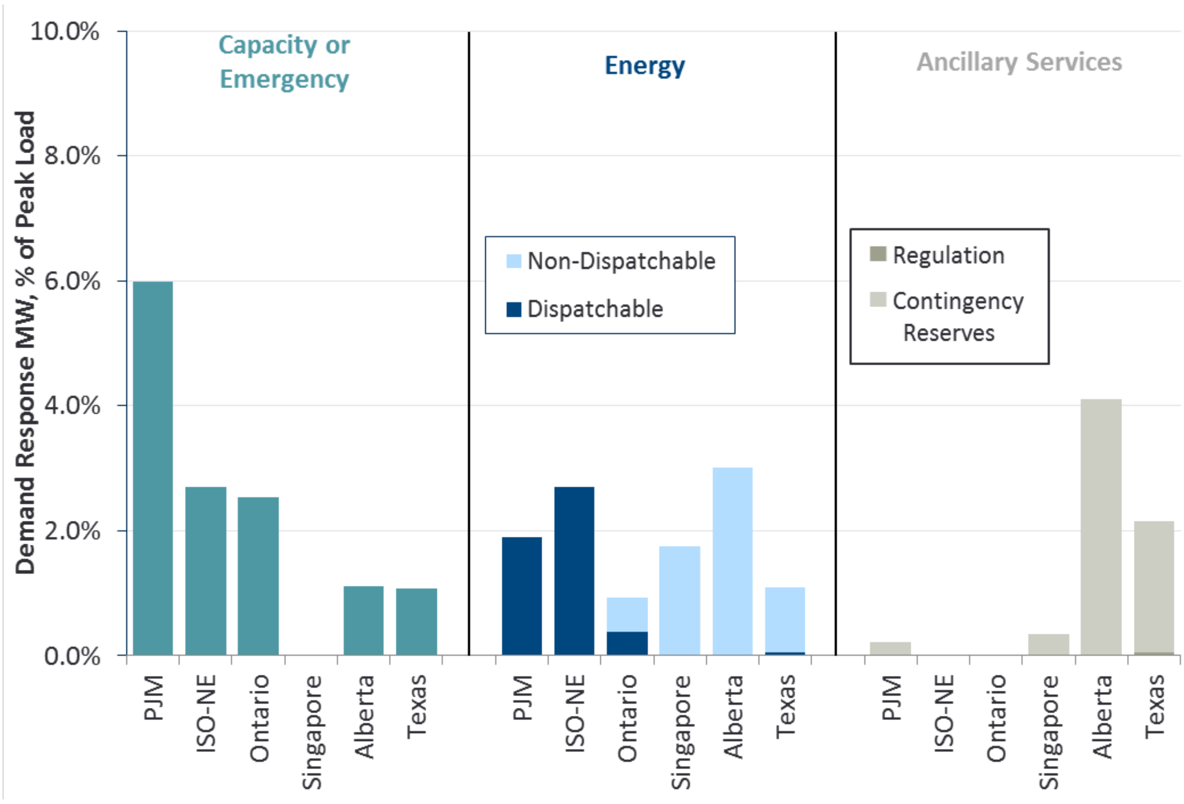
DR can earn revenues by participating in the energy market (whether in jurisdictions described as "energy only" or in the energy market of jurisdictions with formal capacity obligations), either on the demand side by reducing consumption, or on the supply side by effectively "selling back" energy that would otherwise have been consumed. DR can also earn revenues by selling capacity and/or ancillary services. In the markets we have studied, it is difficult to say how much DR participates in the energy market on the demand side as price-responsive load because almost no market participants submit formal bids to purchase energy (with central dispatch by the system operator) and so price-responsive load is "invisible" to the system operator. However, more DR participates by selling capacity than by providing ancillary services or by participating in the energy market on the supply side (supply-side DR is visible to the system operator because it is dispatched). Revenues available to DR tend to be higher from selling capacity than from selling back energy.

In some cases DR programs existed before organized wholesale markets were implemented, and policy makers have adjusted these programs over time to integrate them into the wholesale market design. In other cases, elements of the wholesale market design have been adjusted with the aim of permitting DR to participate on an equal footing with generation.

In some markets DR aggregators are permitted to participate on behalf of a portfolio of underlying loads. Broadly, there are two mechanisms for DR aggregators to participate. One route is by contracting directly with loads and participating in the relevant markets (capacity, AS, or energy as the case may be). This mechanism does not require the DR aggregator to interact with the retailer that supplies the loads. A second mechanism is for the DR aggregator to provide services to the retailer, typically in connection with operating a more traditional utility-led demand response program to reduce its peak loads and associated resource adequacy requirements. In that case the DR aggregator does not participate directly in the wholesale market DR mechanisms.

Figure 22 repeats Figure 3 from section II above, and shows estimates of the quantity of DR participating in wholesale market DR mechanisms. For each market, the quantity of DR is normalized as a percentage of total peak load in that market.

Figure 22
Demand Response Penetration by Market



Sources and Notes:

PJM : All data from PJM's "2014 Demand Response Operations Markets Activity Report." Note that the quantity of DR actually registered for the year may be less than the amount that cleared in the forward capacity auction shown in Figure 14. The capacity bar includes Energy-Only component of Emergency Load Response Program as it involves a voluntary curtailment during emergencies. We were unable to quantify and include demand-side response to wholesale prices.

ISO-NE: Peak load data from ISO New England's website, "Summer 2014 Weather Normal Peak Load," accessed June, 2015. See http://www.iso-ne.com/static-assets/documents/2014/10/summer_peak_normal_2014.pdf. DR data from ISO-NE Internal Market Monitor Report, "2014 Annual Markets Report," May 2015, pp. 93 and 95. See http://www.iso-ne.com/static-assets/documents/2015/05/2014-amr.pdf

Ontario: Data from IESO's "Comparison of 2013 Long-Term Energy Plan to 2013 Actual Results." Capacity bar includes both OPA/IESO DR program MWs and Dispatchable Load MWs. There was an inconsistency between DR reported in the Installed capacity table and the Demand Management table: we used the latter. Energy bar includes both Dispatchable Load and estimated effect of Time of Use Pricing (Non-Dispatchable). We were unable to find reported DR capacities in Ontario's AS markets though participation is allowed.

Singapore: Data from EMC's "Price Information – Capacity for Registered Facilities." Singapore does not currently have any Capacity/Emergency or Energy DR. AS quantity provides primary, secondary, and contingency reserves.

Alberta: Demand Opportunity Service (DOS) is counted as an emergency service as curtailment is only required in shortfall events. Price responsive loads are classified as energy demand response, and loads that participate in supplemental (SUP) and LSSi are included as ancillary services. Note that some loads are price responsive and participate in ancillary services, if participatory in both; the load is counted as an ancillary service. Source: AESO 2011 Annual Market Statistics (http://www.aeso.ca/downloads/AESO_2011_Market_Stats.pdf). There have been minimal changes in participation levels of DR since that date.

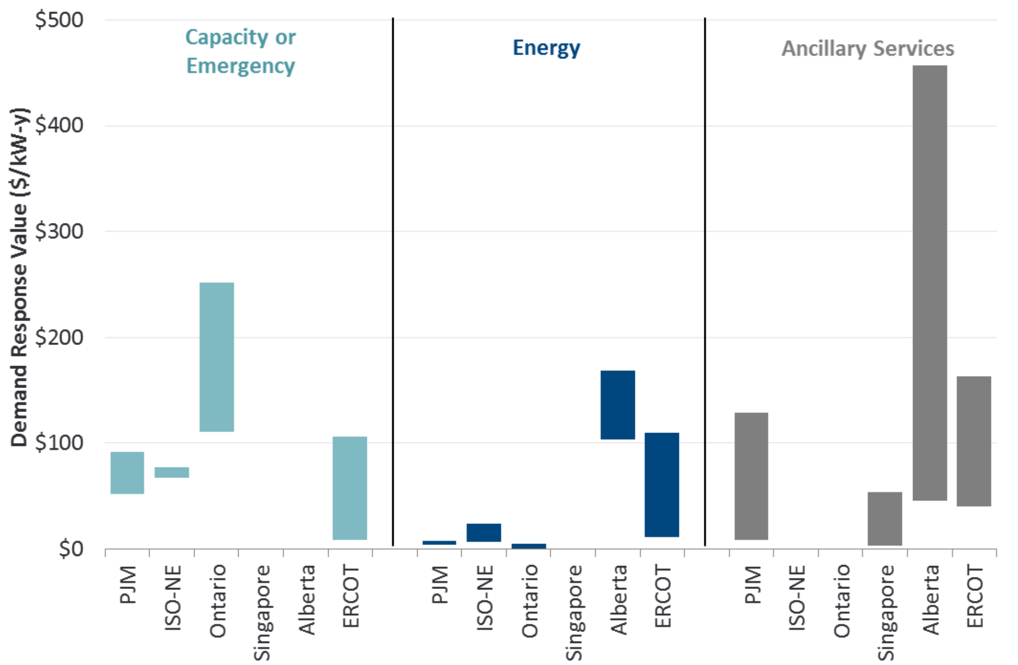
Texas: Emergency Demand Response is the sum of Emergency Responsive Service, and the portions of Transmission and Distribution Service Provider Load Management Programs dispatched during emergencies. Dispatchable Energy includes 30MW of load that were in the process of being qualified to bid in the Real-time market in August 2014. Non-Dispatchable energy is the MW response to high wholesale prices. Regulation is assumed to be equal to the Controllable Load Resources in the market. Loads providing Responsive Reserve are set equal to the maximum procured capacity.

Figure 22 shows that capacity markets (PJM, ISO-NE and Ontario) procure the largest quantities of DR. (Note that while ERCOT does not have a formal capacity procurement program, the system operator does procure an emergency response product from DR providers. Emergency DR in Alberta is simply load with a special class of system access that can be curtailed in the event of an emergency.)

The dark-collared bars in the "energy" panel of Figure 22 show that some DR also participates as energy supply resources in these three markets and is dispatched by the system operators. The light blue bars show estimates of the quantity of price-responsive load (effectively DR that participates on the demand side but which is not dispatched by the system operator). The final panel of Figure 22 shows that the extent to which DR participates in AS markets varies a lot between markets, being a function of the technical design of AS products (which determines whether or not DR can participate). Alberta is unusual in that the geographic and technical characteristics of that market create a large demand for frequency support AS that can be cost-effectively supplied by load.

Figure 23 repeats Figure 4 from section II above. It shows estimates of the revenue earned by a kW of DR in each market and from providing capacity, energy or AS.

Figure 23
Capacity – Normalized Demand Response Value by Product Type



Sources and Notes

PJM: Capacity values represent minimum and maximum capacity market clearing prices over last five years. Energy values represent total energy market DR payments divided by capable MW, minimum and maximum values 2011-2014. Ancillary services range represents minimum revenue for synchronized reserve market from 2011-2014 to maximum value for regulation market from 2011-2014.

ISO-NE: Capacity values represent minimum and maximum capacity market clearing prices over last five years. Energy values represent total energy market DR payments divided by capable MW, min and max values 2011-2014. Total Capacity and Energy payments converted to $/kW-yr rate by dividing by DR capacity in each year. Ranges represent maximum and minimum payments received from 2011 to 2014. Data from Annual Markets Reports of the given year.

Ontario: Capacity revenues based on OPA-reported contract costs for legacy DR2, DR3, and peaksaverPLUS programs. Energy market revenues based on energy margin calculation with an AUD $300/MWh strike price (see Figure 5).

Singapore: Market does not have a capacity or emergency product or an energy product currently. Ancillary Service values represent earnings of DR providing 8760 hours of reserves at 2014 prices assuming they provide primary reserves in the lowest quality group (group E) at the low end and contingency reserves in the highest quality group (group A) at the high end. Data from emcsg.com/marketdata/priceinformation.

Alberta: We do not report revenues for emergency DR in Alberta due to the idiosyncratic nature of the DOS program. Energy revenues are the annual avoided costs that existing Price Responsive Loads realize converted to $/kW-yr (based on AESO provided data). The Ancillary Service revenue range is capped on each end by the hypothetical revenue earned from providing supplemental reserves in all hours of 2013 (upper end), and by the hypothetical revenue received by $5/MW availability payment for providing LSSi in all hours of 2013 (lower end).

Texas: Emergency Revenues are capped at ERS payments assuming participation in all four periods, and have a floor that assumes participation in only one of the periods. In Ancillary Services revenue calculations, the price is converted from $/MWh to $/kW-yr using a demand factor of Average/Maximum RRS MW awarded.

In the central "energy" panel of Figure 23, the estimated revenue available to a DR provider is mostly a function of the size and frequency of price spikes. If prices rarely spike, a DR provider will not expect to earn much revenue by selling back electricity in high-priced hours.

In the left panel of Figure 23, we observe that for the markets with capacity mechanisms, the revenue available is much larger than the revenue available from participating in the energy market alone. This is consistent with the thesis that capacity mechanisms are the most significant route for integrating DR into wholesale markets. Energy market revenues are low for these markets because energy prices tend not to be so volatile (see Figure 2 and Table 2 above). The very high capacity market revenues available in Ontario are an outlier.

The AS panel of Figure 23 shows some very wide variations both within and between markets, but, where DR is able to participate in AS markets, the revenues can be significant. The highest value AS products, such as supplemental reserve in Alberta, cannot be provided by all DR resources. Note also that the estimates in Figure 23 are revenue estimates and do not take into account the costs of providing these services.

Note that we describe DR performing three *functions*: energy, ancillary services, and capacity. In contrast, our report is organized so as to distinguish between two different types of *jurisdictions*, which we refer to as "Energy-Only Markets" and "Markets with Capacity Obligations". DR could potentially provide all three functions in any jurisdiction.

B. Demand Response and the Ancillary Service Function

In AS markets DR may participate in programs specifically designed to attract DR providers, or DR may compete with generators to provide AS products that can be provided by both DR and generation. For example, in Alberta the LSSi product is specific to DR providers, but DR and generators compete to provide supplemental reserves. In Alberta DR is in addition eligible to provide spinning reserves, alongside generation, although in practice it does not do so.

In our review we did not come across significant controversies with respect to DR provision of AS. Measurement of availability to provide AS and delivery of AS when called is straightforward and does not, for example, give rise to the "baseline" controversies seen with some mechanisms for DR to participate in energy markets on the supply side.

The LSSi product in Alberta is interesting as an example of a mechanism which appears to provide DR with a significant revenue stream and also seems to be working well to bring benefits to the market as a whole. The technical and geographic characteristics of the Alberta market are such that a large interconnector with neighbouring British Columbia is a significant source of (relatively cheap) supply. The interconnector is so large that the amount of import capacity that can be used is sometimes limited by the quantity of fast-acting frequency support within the Alberta market that would be available if the interconnector were to trip. This constraint (rather than the physical characteristics of the interconnector itself) limits the quantity of imports, at least in some hours. The LSSi program was specifically designed to allow DR providers to supply additional frequency support over and above the quantity available from other sources (generation). The program has been successful in bringing additional frequency support to the market and permitting a greater quantity of import capacity to be made available.

We note that several markets are working to implement the principle that AS product design should permit DR and generation resources to supply the product on an equal footing.[136]

C. Demand Response and the Capacity Function in Markets with a Capacity Obligation or Emergency Standby Programs

We noted above that capacity mechanisms provide a large source of revenue to DR resources in several markets, and that where these mechanisms exist, they are the most significant route for integrating DR resources into wholesale markets. In the ERCOT market which is energy-only and does not have a formal capacity mechanism, an emergency response product has been introduced which is in some respects similar to a capacity mechanism. ERCOT's emergency response product was initially only open to DR resources.

The evolution of the detailed design for including DR resources into the capacity market mechanism in PJM illustrates some important issues. For example, the principle of treating DR and generation resources equally seems a sensible starting point for mechanism design. However, the technical characteristics of generators and DR resources are different. For example, a generator is likely to be available year-round, apart from occasional planned maintenance outages and random forced outages (especially if it has firm fuel supplies and is well weatherized). However, the underlying loads which allow DR to provide a capacity product may be seasonal, such that the capacity that can be supplied by the DR provider is also seasonal.

To the extent that the seasonality of capacity that DR providers can provide is correlated with the seasonality of demand peaks in the market as a whole, DR providers may be able to provide most capacity at times of the year when the system needs most capacity. PJM's experience has been that when the quantity of capacity provided by DR was relatively low, it was possible to procure capacity from DR providers that were not available year round without adverse impacts on reliability. However, as the proportion of capacity supplied by DR resources increased, the system operator determined that it was necessary to adjust the mechanism design in order to increase the quantity of year-round capacity. These adjustments have only recently been implemented, so there is limited experience with the new approach. However, the changes seem to have reduced the overall quantity of capacity supplied by DR resources.

D. Demand Response and the Energy Function

Energy markets (whether in jurisdictions described as "energy only" or in jurisdictions with a formal capacity obligation) are different from AS and capacity markets in that retailers and load customers have a way to "participate" in the energy market, on the demand side, by adjusting consumption in response to price. This DR participation may be significant in some markets but is "hidden" from the system operator in the sense that the DR is not submitting formal bids and is not being dispatched by the system operator.

[136] See discussion above of Alberta and ISO-NE.

In some market designs separate mechanisms exist to integrate DR participation into the wholesale energy market. Market participants on the demand side may have the option to submit formal bids (price-quantity schedules) and be centrally dispatched. In these markets, for the loads that participate in this way, DR integration into the energy market on the demand side is visible to the system operator and the demand response is "firm" because the load is responding to dispatch instructions. We understand that, in Australia's NEM, currently it is voluntary for price-sensitive loads (greater than 30 MW) to become "scheduled loads", submit price-quantity bids and comply with dispatch orders. Some pumped-storage pumps are scheduled, but most market participants on the demand side are not.[137] A mechanism to permit loads to bid has the advantage that the associated DR is visible to the system operator and is dispatched. However, there may be additional costs to market participants from participating in this way relative to the alternative of participating without being scheduled. If market rules allow loads to be dispatched, many loads may prefer to remain unscheduled. Loads may incur system set-up costs to be centrally dispatched, and may be exposed to the risk of penalties for non-performance.

It is more common for there to be mechanisms to integrate DR into the energy market on the *supply* side, with the DR effectively "selling back" energy. These mechanisms operate independently of the purchase of energy through the regular settlement process. The DR is dispatched by the system operator, and the DR provider is paid a dispatch price for the energy notionally supplied.

Through our review we have identified three key design questions for these mechanisms:

- how the price for energy provided by DR resources relates to the wholesale market price;
- how to determine the quantity of energy provided by a DR resource that is dispatched by the system operator; and
- how DR resources providing AS or capacity resources influence the wholesale energy price.

1. The Energy Price Paid to DR Providers

When DR participates on the demand side by adjusting the quantity of energy consumed in response to the wholesale price, the DR provider effectively "receives" a price for the energy not taken equal to the price that it would otherwise have paid to consume the energy. Equally, where DR participates formally and is dispatched on the demand side, the effective price for the DR is the price at which the DR is dispatched.

In markets where there is a mechanism to integrate DR on the *supply* side, there is an ongoing dispute over the price that should be paid for energy supplied by DR resources. In

[137] We also understand that a recent rule change proposal would make it compulsory for price-sensitive large loads to bid into the energy market. (Whitby, Roger, Executive Officer, Trading (Snowy Hydro Ltd.) to John Pierce, Chairman (Australian Energy Market Commission), re Proposed rule change: Demand Side Obligations to Bid into Central Dispatch, June 10, 2015.)

the early days of DR participation in PJM's energy market, the DR provider was paid the full wholesale price for the energy supplied (or not consumed). This payment was made without any adjustment for the fact that the underlying load customer and/or retailer also benefitted from a reduced energy bill consequent on having curtailed load. Over time PJM's mechanism was adjusted to reduce the payment to the DR provider to take into account the parallel benefit (reduced energy bill) for the underlying load. The FERC stepped in[138] to require the original approach of paying the full wholesale price to the DR provider, without adjustment. (We illustrated the economic distortions this approach can cause in Section IV.A.4.) A circuit court overturned Order 745, but primarily based on jurisdictional grounds without ruling directly on the compensation issue. An appeal is currently pending before the US Supreme Court.

Singapore's mechanism for DR to participate in the wholesale market takes a different approach for calculating the price to pay DR providers for energy not consumed, but similarly will result in a payment greater than the system price because an additional incentive is paid. The amount of the incentive is calculated based on an estimate of DR's contribution to reducing the system price. In terms of overall economic efficiency, this approach suffers the same problems as the US FERC's "net benefits test" described in Section IV.A.4: customers benefit from reduced system prices, but these are transfer payments from producers and do not represent a reduction in total system costs (although in Singapore DR is only permitted to participate when the wholesale market price is high). Transfers from producers to consumers cannot be sustained in the long run because prices will have to cover the cost of new generation entry, with or without demand response. Generators may also perceive high regulatory risks if policy makers appear to pursue policies aimed at suppressing prices rather than improving efficiency, thus raising the cost of investing.

The design of both the Singapore and FERC approaches seems to have been influenced by the claim that all loads benefit, in the short term, from reduced wholesale prices as a result of DR integration. However, the design of these approaches does not take account of total (producer and consumer) surplus or total resource costs, so will lead to less economically efficient outcomes.

2. Determining the Quantity of Energy Provided by DR

The second key design question is how to determine the quantity of energy that is "supplied back" by a DR provider. This question arises because customers are not required to submit formal "bids" to the system operator for their demand. Rather, they have an option to consume as much as they want. As a result, in order to measure the quantity of DR provided, it is necessary to define a "baseline" level of energy that would have been consumed by the load associated with a particular DR provider if the DR had not been dispatched. The quantity of energy "supplied back" is then the difference between the baseline quantity and the metered quantity. The methodology for determining the baseline is therefore important because the level of the baseline influences the payments made to the DR provider, and in

[138] 134 FERC ¶ 61,187, FERC Order No. 745, issued March 15, 2011.

some markets enforcement action has been taken over allegations that DR providers have altered consumption behaviour in an attempt to increase baselines.

The design of the mechanism for integrating DR in Singapore is different and avoids the need for an administratively-determined baseline: in order to participate, DR providers have to notify the quantity of energy that will be taken if the DR is not dispatched, as well as the quantity of energy that will be "supplied back" if the DR is dispatched. The DR provider will be subject to penalties if actual consumption does not correspond to the notified quantities (providing an incentive to submit an accurate baseline).

3. Determining the System Price When DR is Dispatched

The third important design question connected with integrating DR into wholesale energy markets relates to the mechanism for determining the wholesale price under conditions when the system is short of resources. As the system operator calls on DR providers to curtail under capacity/emergency or AS mechanisms, the load on the system will fall as DR providers curtail. In some markets, the intended reduction in system load has had the unintended consequence of reducing the wholesale price. Clearly, when the system is sufficiently stressed that the system operator is dispatching DR resources to curtail load, falling wholesale prices could exacerbate reliability risks. Various technical fixes to the mechanisms for determining the system price have been developed to address this.

List of Acronyms

4CP	Four Coincident Peaks
AEMC	Australian Energy Market Commission
AESO	Alberta Electric System Operator
AM	Ante Meridiem
AS	Ancillary Services
AUD	Australian Dollars
BC	British Columbia
BCDR	Base Capacity Demand Resource
BRA	Base Residual Auction
CAD	Canadian Dollars
CBL	Customer Baseline
CLR	Controllable Load Resource
CONE	Cost of New Entry
CPDR	Capacity Performance Demand Resource
CSO	Capacity Supply Obligation
DALRP	Day-Ahead Load-Response Program
DC	District of Columbia
DG	Distributed Generation
DOS	Demand Opportunity Service
DR	Demand Response
DRA	Demand Response Aggregator
EDF	Électricité de France
EILS	Emergency Interruptible Load Service
ELRP	Emergency Load Reduction Program
EMA	Energy Market Authority
EMC	Energy Market Company
ERCOT	Electricity Reliability Council of Texas
ERS	Emergency Response Service
FCM	Forward Capacity Market
FEOC	Fair, Efficient, and Openly Competitive
FERC	Federal Energy Regulatory Commission
FSL	Firm Service Level
GA	Global Adjustment
GW	Gigawatt
HOEP	Hourly Ontario Energy Price

IESO	Independent Electricity System Operator
ILR	Interruptible Load for Reliability
ILRAS	Import Load Remedial Action Scheme
ISO	Independent System Operator
ISO-NE	Independent System Operator of New England
kW	Kilowatt
LaaR	Load acting as a Resource
LMP	Locational Marginal Price
LRP	Load Response Program
LSS	Load Shed Service
LSSi	Load Shed Service for Imports
MSA	Market Surveillance Administrator
MW	Megawatt
MWh	Megawatt Hour
NEM	National Electricity Market
NEMS	National Electricity Market of Singapore
OPA	Ontario Power Authority
PJM	PJM Interconnection
PM	Post Meridiem
QSE	Qualified Scheduling Entity
RAP	Regulatory Assistance Project
RTEG	Real-Time Emergency Generation
RTO	Regional Transmission Organization
RTPR	Real-Time Price-Response
SEL	Smart Electric Lyon
SMD	Standard Market Design
T&D	Transmission and Distribution
TPRD	Transitional Price Response Demand
WECC	Western Electricity Coordinating Council

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