Oral Sessions | Symposium (Hybrid)

Session 18
Markets, incentives and coordination for DER

Thu. Apr 7, 2022 9:00 AM - 10:30 AM Room C2 (1F)

[C000077] International Perspectives on Achieving Cost Impacts with Flexible Demand Response

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Keywords: Flexible Demand Response, Avoided Cost, Distributed Energy Resource, Demand Response Applications, Power System and Market Functions, Demand Response Programs, Enabling Technologies

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CIGRE 2022 Kyoto Symposium, Japan

Power System Transformation including Active Distribution

C000077

International Perspectives on Achieving Cost Impacts with Flexible Demand Response

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SUMMARY

Around the globe, demand-side programs are expanding to recognize the growing importance of flexible demand response (DR) to support power system and market functions. DR program activities have been reviewed by CIGRE Working Group C5-31. Survey responses reveal DR employed to support power system functions of the Market Operator, Transmission System Operator (TSO), Distribution System Operator (DSO), and Load Serving Entity (LSE). Both direct participation in electricity markets as well as in retail DR programs were surveyed.

Leveraging the working group's international research, this paper provides examples of DR programs supportive of multiple power system planning and operational functions performed across the electricity value chain. Specific program examples and avoided cost indications attributed to the programs were surveyed. How avoided costs are expressed is illustrated for different regions as well as the total load served and the level of program participation.

The paper begins by providing a taxonomy of distributed resources and DR programs to clarify use of terminology and scope of programs surveyed. Both distributed energy resources (DER) capable of producing electricity and demand responsive loads may contribute to adjusting net load measured at the customer meter, in support of power system or market needs. Regional DER/DR programs are compared and contrasted along with resulting avoided cost indications revealed through survey findings. The paper concludes with remarks on future work needed to advance flexible DR in actual implementations designed for avoided cost capture.

KEYWORDS

Flexible Demand Response, Avoided Cost, Distributed Resource, Demand Response Application, Demand Response Program, Power System and Market Functions, Wholesale and Retail Cost Impact

INTRODUCTION

In this paper, Distributed Energy Resource (DER) refers to distributed generation (DG) and distributed energy storage technologies (ES) that are interconnected to the power system at distribution voltage levels to provide electricity capacity, energy, or grid support as needed. A fundamental difference between DER and demand responsive loads is that only the former is capable of producing electricity [1]. Electricity producing DER (e.g., photovoltaics (PV), storage, vehicle-to-grid technologies) and demand responsive loads (e.g., interruptible/batch industrial processes; space conditioning, water heating and pumping technologies) can be engaged in demand-side programs. The differences between DER versus DR programs are clarified below. This paper excludes programs that do not fall under the ambit of responsive demand, although there is possibility of program advancement to become capable of demand response. Particular use of terminology is first summarized below, to clarify terms employed in the remainder of this report.

Demand Response (DR) occurs when there is a coordinated adjustment in net load measured at the customer meter due to distributed resources, such as demand responsive loads, DG, ES, and electric vehicles in support of electric power system or market functions [2]. The desired adjustment in output is often driven by market opportunities, demand-side program provisions, and grid operating requirements. This adjustment is demonstrated via a variety of mechanisms such as manual actions, direct control, and demand limiting control. DR is incentivized through a variety of program approaches (e.g., financial incentives, discounted rates, or penalties for deviating from firm commitments).

The scope of programs surveyed include both dispatchable DR programs and price responsive DR with automation. Dispatchable DR programs generally trigger a quantity of response from distributed resources as needed to support system operations (e.g., day-ahead or day-of when the response is needed). This is in contrast to programs with no provision for dispatchable DR such as time-of-use rates and real-time pricing. Nevertheless, price responsive programs may also include designs supportive of power system and/or market operational needs (e.g., provisions for controls or automation to actuate price-based response), and consequently are within scope of the survey. Programs designed to advance energy efficiency or beneficial electrification are outside the scope of the survey.

In the case of DER asset types capable of generating electricity, an interconnection agreement is generally required. The agreement expresses terms that dictate whether DER export is permitted or in the case of behind-the-meter (BTM) DER, whether the DER is only configured to serve facility loads. In this way, DER export programs are distinguished from most DR programs, which are primarily designed to reduce purchased power from the grid [3].

This paper compares regional resource and customer mix in participating regions surveyed by CIGRE Working Group C5-31 (Wholesale and Retail Cost Impacts of Flexible Demand Response). The paper then elaborates on a collection of program examples that contribute to supporting multiple functions in the electric power industry with DR. Such programs may better contribute to sector coupling solutions by providing demand flexibility supportive of renewable integration as well as cleaner and greener energy systems. Concrete program examples are provided along with avoided cost indications from participating regions: Australia, India, U.S., Brazil, and Gulf Cooperation Council (GCC).

REGIONAL SYSTEMS

The annual system load of 9 participating regions are shown in Figure 1, including U.S PJM, India, GCC, Japan, Brazil, Ontario Canada, South Africa, Portugal, Australia (NEM Bulk) and China. Values are compared for the years 2018 and 2019. The annual system load is comprised of the total electricity consumption of different sectors, and indirectly reveals the total electricity generated, + energy imported from / - energy exported to neighbouring countries or regions (if any) minus the transmission and distribution losses. In real-time operations, maintaining system balance between load and generation is critical for stable grid frequency, such that the larger the grid, the bigger the challenge to maintain system balance. DR programs play a crucial role in maintaining grid stability, among other contributing factors like system inertia and type of loads connected to the power system (e.g., power electronics). DR may be employed to support additional functions discussed in this paper.

Among the regions surveyed, China has the highest system load at about 7.2 million GWh in 2019, followed by India with a system load of 1.29 million GWh, and then Japan. Opportunities for DR can be high in countries with the greatest amount of peak load. DR is useful to the system operator as an emergency measure for system balancing as well as a source of ancillary service reserves. In the U.S., PJM reported an annual system load of 0.77 million GWh in 2019, multiple applications for DR, and decreasing system load from 2018 and 2019. For India the reference has been taken from [4].

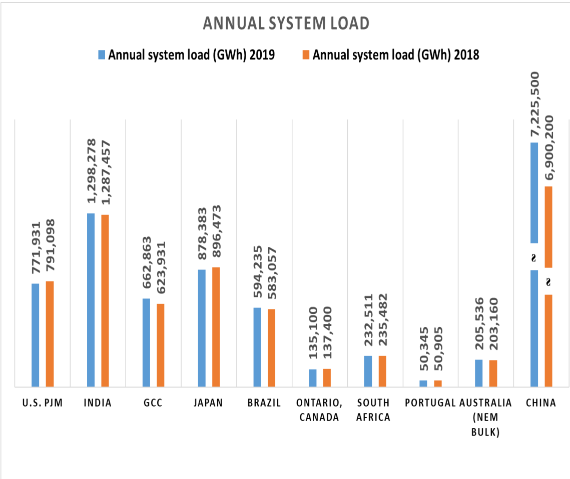

Figure 1: Annual System Load Comparison

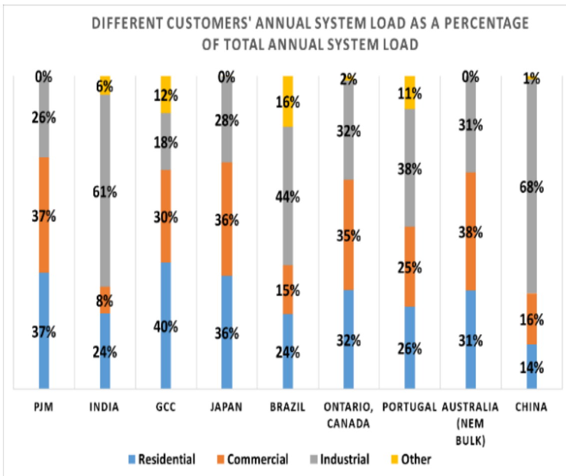

Figure 2: Customer Breakdown Comparison

Figure 2 summarizes the proportion of customers by class for the 9 regions. Collectively, end-use customers determine to the effectiveness of DR programs. Customers are broadly categorized into residential, commercial, industrial, and other classes in the figure. Residential end uses mainly include household loads like electric fans, room lights, water heaters, room purifiers, air conditioners, etc., while commercial end use stems from office and institutional buildings (electric lights, fans, air conditioners, heat pumps, plug loads, elevators etc.), airports, hospitals, etc. Industrial end use consists of different categories of industrial production such as food, chemical, steel, alloys, etc. Electricity end use under the category of "other" consists mainly of streetlights and other exterior lighting outside of buildings. For India the reference has been taken from [5].

Residential consumption of electricity is the highest in GCC, accounting for 40% of the overall annual system load, followed by PJM and Japan. The lowest percentage of residential load is in China at 14% of the annual system load. Commercial load is highest in the Australian NEM footprint at 38%, followed by PJM and Ontario, Canada. Industrial load is highest in China at 68% of annual system load, followed by India at 61% of annual system load. This indicates a greater potential of DR programs to engage industrial customers. Brazil and GCC have the highest percentage of "other" loads at 16% and 12% of annual system load, respectively.

REGIONAL PROGRAMS

Table 1 summarizes select regional programs, each with multiple applications for employing DR. Each program is named in the row followed by indications with a "1" under the columns for which DR may be triggered in application. Program participation levels and avoided costs are also indicated in the table, where reported. The reader will note the unit of measure for reporting avoiding costs depends on the application for which DR is employed. For example, avoided cost of DR employed for Balancing Energy is typically expressed in $/MWh, for Reserve in $/MW per time period of reserve provision, Economic Dispatch in $/MWh, Generation/Transmission/Distribution Capacity in $/kW/year, and Emergency DR in $/kW/year. Exceptions are noted in the table. Details by region are provided next.

Table 1: Regional DR/DER Programs with Multiple Applications

Region	Program Name	Application									Participant		Avoided Costs
		RT balancing	Reserve, Tier 1	Reserve, Tier 2	Reserve, Tier 3	Economic dispatch	Distribution capacity	Transmission capacity	Generation capacity	Other	#	MW	Balancing Energy: $/MWh, Reserve: $/MWh, Economic Dispatch: $/MWh, Generation/Transmission/Distribution Capacity: $/kW/year, Emergency load: $/kW/year, unless otherwise mentioned.
U.S PJM	1. Emergency DR								**1**	**1**		9583	$100/MW-day (2019/2020), $76.53/MW-day (2020/2021)
	2. Economic DR		**1**	**1**	**1**	**1**						2777	$418.56/MW-day (March 2020), $373.44/MW-day (June 2020)
	3. Price Responsive DR	**1**							**1**			558	$113.14/MW-day (2020/2021)
India	4. Automated DR pilot program	**1**				**1**	**1**		**1**	**1**	250	34	Specific values for the avoided costs in this program were not available
	5. Behavioural DR pilot program	**1**				**1**	**1**		**1**	**1**			
	6. Voluntary Load Curtailment pilot program	**1**				**1**	**1**		**1**	**1**			
GCC	7. High voltage C&I load curtailment	**1**		**1**				**1**	**1**				unavailable due to the preliminary stage of the program
BR	8. DR Pilot Program					**1**			**1**				
Australia	9. Battery Virtual Power Plant	**1**		**1**			**1**						Specific values for the avoided costs in this program were not available
	10. Simply Energy VPPx	**1**		**1**						**1**			0.385 M$. (Simply Energy annual estimate)
	11. VPP in SA	**1**		**1**			**1**			**1**			Specific values for the avoided costs in these program were not available.
	12. C&I DR	**1**		**1**		**1**							
	13. Controlled Load						**1**	**1**					Annual peak demand reduction at LRMC of distribution and transmission capacity: 19.9 M$.

Australia

Regional market structure

Australia's National Energy Market (NEM) comprises the country's eastern states (Queensland, New South Wales including the Australian Capital Territory, Victoria, South Australia and Tasmania).
Key aspects of the electricity market structure are as follows:

- It is an energy-only market and uses a gross pool, in that generators 'sell' all of their output into the pool and retailers 'buy' all of the electricity they consume from the pool.
- Recent elements have been introduced placing capacity obligations on retailers under certain circumstances.
- A contract market provides financial hedge products for the volume and price risks that buyers and sellers face in the gross pool.
- There is a significant amount of both large and small-scale variable renewable energy generation plants in the market. As a result, retailers can now purchase an increasing amount of generation from customer-owned rooftop PV, which essentially reduces the amount of electricity they need to purchase from the pool. Where rooftop PV is paired with a behind-the-meter battery, the home's consumption and export can be managed to reduce costs for both the customer and the supply chain.

The industry has been vertically unbundled. The generation and retail functions are competitive. Network businesses (transmission and distribution) are regulated monopolies. Regulated monopolies cannot own generation or retail businesses, except in very limited cases, or where this is done through a fully separate subsidiary. Generation businesses can own retail businesses (and vice versa); in either case, this stakeholder is referred to as a ‘gentailer’. Most of the industry has been privatised though the Commonwealth and some state governments retain ownership of specific parts of the supply chain.

DR Programs and Avoided Costs

Rows 9 – 13 in Table 1 represent the most common types of DR and DER programs currently on offer in the NEM. As can be seen, these programs can be sponsored by various parties including gentailers, retailers, or distribution or transmission system businesses, and can be used in a number of different applications that result in different costs being avoided.

The same program can be used in different applications as is also shown in Table 1, and different program sponsors have different motivations for their programs and different benefits that they can leverage from the sponsorship of those programs. For one, gentailers have more reasons for leveraging DR. A gentailer can use DR from demand responsive loads or DER to balance its supply/demand position (e.g., self-supply for both the generation and retail sides of the business) as well as to participate in the ancillary services (e.g., frequency control) market. The self-supply aspect may allow the generation side of the business to sell more cap contracts than it might otherwise be able to. In addition, the program may increase the ability of the retail side of the business to gain and/or retain retail customers. Although not shown in the table, a number of retailers in the NEM also sponsor DR programs in the residential market, where customer satisfaction, retention and acquisition are often the primary benefits. Program 10 is an example of such a program.

A retailer may also be able to provide paid services for the delivery of DR/DER to the local distribution (and transmission) network for congestion reduction at times of local peak demand and/or voltage control when needed during periods of high PV export and low underlying demand. Both services are provided and remunerated based on local network area needs and avoided costs. Program 11 includes this sort of application. Program 12 does not include this application, but networks can commission retailers to dispatch C&I DR to manage localised network congestion.

Distribution businesses offer DR (e.g., direct load control) and DER programs most commonly on an area-specific basis to defer capital expenditure for local infrastructure augmentation. Programs 9 and 13 are examples of this type of program. Recently, distributors are becoming increasingly interested in programs to help manage voltage and increase DER hosting capacity, particularly in areas where the penetration of rooftop PV systems is high and/or growing rapidly. Although distribution businesses cannot offer DR into the wholesale or ancillary services markets, retailers or third parties that provide DR to distributors can do so.

Aggregation of DR by third parties for use in the ancillary services market has existed for about five years in the NEM. A change in the rules that govern the NEM has recently made it possible for third-party aggregators that are not the retailer serving the customer to also bid DR from end customers directly into the wholesale market.

India

Regional market structure

The Indian regional electricity market comprises long, medium and short term (bilateral/collective) contracts with transmission access taken from CTUIL (Central Transmission Utility of India Limited) for LTA(Long Term Access) and MTOA(Medium Term Open Access) and RLDC(Regional Load Dispatch Centre)/POSOCO (Power System Operation Corporation Limited) for STOA(Short Term Open Access) after due consent from SLDC/STU (State Load Dispatch Centre/State Transmission Utility) if any state network is involved. The collective market runs on a Day-Ahead basis for each 15-minute time block of the next day, with a unique price discovered for each block. A real time collective market also runs on a 30 minute ahead basis. Market splitting is used to relieve Congestion. Deviation charges are levied on the regional entities based on the difference between the actual injection or drawl from the grid with respect to its injection/drawl schedule. The Indian electricity industry is vertically unbundled. Generation is a delicenced activity while Transmission, Distribution and Trading require a licence. SLDC, STU, CTU, the transmission licences (owners of transmission lines and equipment) cannot engage in electricity trading business, while RLDC (POSOCO) is barred from entering the business of generating electricity, as per Indian Electricity Act 2003.

DR Programs and Avoided Costs

Distribution utilities in the metropolitan cities of India are exploring the possibility of Demand Response. Pilot projects were taken up by the TPDDL utility in Delhi. Rows 4-6 in Table 1 represents the most common types of dispatchable DR programs in India that are used by the Discom named TPDDL (Tata Power Delhi Distribution Limited) [6], [7] and TPC-Mumbai (Tata Power Company) [8]. The purpose of these programs is to reduce the consumption of electricity in the control area of the distribution license under the following (but not limited to) circumstances: when there is a sudden occurrence of demand peak, increase in the drawl of electricity from outside, or when the wholesale price of electricity in the market is high. The operator in this scenario either asks the customer to manually switch off the load, or he himself can switch off the load from the control room. The total cost of building the infrastructure for such a DR program is borne by the distribution licence. The primary cost that is avoided by the DR programs is the peak procurement cost of electricity. The price incentive paid to the customer for shedding their part load is often of lower value than that to procure the electricity from the outside market. If the load was not shed due to the non-availability of such DR programs, either the Discom must buy electricity or pay the deviation charges for drawling more than what is scheduled. This deviation charge is paid to the respective SLDC under whose control area the Discom belongs. Unscheduled drawl from the grid would also reflect in the states' overall schedule and the RLDC would impose deviation charges on the violating state. This is also in violation of the IEGC 2010 (Indian Electricity Grid Code) and amendments thereof. RLDC sends deviation violation messages, as per CERC regulations to such violating states. Thus, by dispatching the DR and maintaining the drawl within its schedule, the deviation charge liability to the state is also reduced. Overall grid security is maintained and the task of Disocm, SLDC and RLDC becomes easier. The control area is pictorially represented in the Figure 3.

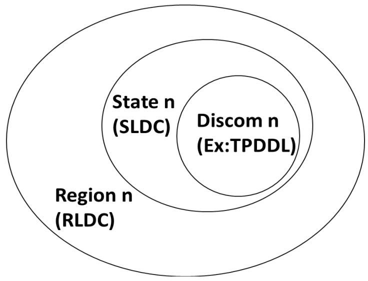

Figure 3: Control area of RLDC, SLDC and Discom.

Over the long-term, DR also reduces the peak load of the Discom's control area. Thus, it reduces the usage of distribution and generation capacity. Avoided cost of capacity may be calculated over the year and expressed in $/kW/year.

U.S. PJM

Regional Market Structure

The regional transmission organization (RTO) PJM operates a series of markets to procure installed capacity, day-ahead energy, ancillary services (e.g., synchronized reserves), real-time balancing energy, and frequency regulation reserves. Demand response resources are permitted to participate in all these markets, including PJM's Regulation D market, so long as the resources can qualify and meet technical requirements. For example, metering requirements include 1-hour interval after-the-fact metering for capacity market participation; 1-hour interval after-the-fact metering or 5-minute interval for energy market participation; 1-minute interval after-the-fact metering for synchronized reserve participation; and real-time telemetry (e.g., 2-second scan rate) for regulation market participation.

DR Programs and Avoided Costs

Rows 1-3 in Table 1 represent PJM's DR programs. Generally, a generator that bids in PJM's capacity market and clears is then obligated to bid into the day-ahead energy market in PJM. However, under Program 1 (Emergency DR), a DR resource is not obligated to bid into day-ahead energy market if it clears as capacity, but it must respond to emergency dispatch. Such an emergency DR resource is subject to pay-for-performance penalties. This program enables third-party aggregators (i.e., curtail service providers) and load serving entities (LSEs) to engage customers with direct financial incentives to participate during emergency events only. Program 2 (Economic DR) allows these stakeholders to earn an additional revenue stream from market participation with DR resources by bidding into markets (e.g., synchronized reserve, day-ahead energy, real-time energy, or frequency regulation). A DR resource can offer the same capacity into multiple markets (e.g., day-ahead energy and sync reserve) but cannot be dispatched for multiple markets with the same capacity simultaneously (e.g., cannot assign the same MW for both frequency regulation and sync reserve at the same time). Under Program 3, there is no payment for load curtailment, but a load serving entity can derive value by avoiding installed capacity costs with DR. Program 3 participation received uptake for the first time in June 2020 and the second capacity market with a PRD option opened in 2021, so early results are still being determined. In all three cases, avoided costs are expressed in $/MW-day.

Brazil

Regional market structure

The Brazilian government oversees all electricity market activities in Brazil and maintains Brazil as an open access energy market, declaring all concessions for major energy services must go through a public bidding process. The two authorities Ministry of Mines and Energy (MME) and National Agency of Electric Energy (ANEEL) are responsible for granting concessions and permissions of electric power services and facilities. Agents in the market include distributors, generators, sales agents, and special consumers. They all operate within two market schemes: i) the Regulated Contracting Environment and ii) Free Contracting Environment. Transactions in the Regulated Contracting Environment take place between distributors and generators under auctions provided by the Chamber for Commercialising Electricity (CCEE). Contracts undergone within these auctions demonstrate various regulations. Buyers are subject to a monthly energy bill that encompasses distribution and generation charges regulated by the governing body. In the Free Contracting Environment, generators, importers and exporters of energy, and consumers can determine their own contracts. All contracts within the market are recorded by the CCEE. The CEEE is responsible for determining differences between electricity contracted and actual generation amongst the contracted agents.

DR Programs and Avoided Costs

Brazil possesses a pilot DR program that supports economic dispatch and capacity for generation that aims to replace high price thermal dispatch decided by the government due to energy security reasons. Instead of dispatching a new generation source using economic dispatch, the National Power System Operator (ONS) disconnects one of the loads engaged under the pilot program. At the time of financial settlement, the agents exposed in the wholesale market (e.g., generators when they do not generate what they should or consumers who do not have contracts to cover their consumption) pay for "cutting" load just as would if that agent had to pay for additional generation. The Program underwent changes in 2020 and since then, instead of covering only two regions of Brazil, the North and Northeast, it started to allow the adhesion of qualified consumers located in any region. Additionally, the duration of the program was also changed, which was scheduled to end in June 2021 and is now valid until June 2022. Brazil's DR Pilot Program is in its early stage without data on avoided cost, but the last report available shows an avoided cost of 63.50 $/MWh in that specific case.

The DR pilot program is now being discussed in an ANEEL Public Consultation. Recommendations from the pilot project includes: Making flexible the requirement for connection to the ONS supervision network, to expand those eligible to participate in the program. Allow participation of consumers in all submarkets of the SIN to expand eligible participants. Offer two choices of consumer baseline calculation method. Exclusion of consumption resumption ramp after product delivery. Inclusion of a product with a fixed payment for its availability. Combing Demand Response offers (REN 792/2017) and the offers of thermal plants with a view to maintaining the operating power reserve (REN 822/2018).

GCC

Regional market structure

As depicted in Figure 4, GCC has an energy market (most active), spinning reserve market, and generation capacity market to fulfill peak load demand of member states. A bilateral market has been in place since 2012 for the GCC region which is interconnected by GCC Interconnection Authority (GCCIA) – an entity formed by cooperation of the six GCC countries. The region has witnessed significant energy trade among the member countries since 2016 mainly through bilateral energy swap contracts. However, the past few years have seen considerable bilateral transactions on a cash basis. The increase in bilateral contracts has seen considerable reduction in power trade prices over the past 5 years. With more liquidity expected in the market, GCCIA (acting as a Market Operator) plans to introduce the Day-Ahead Market soon. Currently, only the bilateral market exists at the GCC regional level. While the members have the right to submit energy schedules for power trade year-ahead, month-ahead, day-ahead and revise schedules up to 3 hours before the delivery, there hasn't been any significant power trade activity close to real-time.

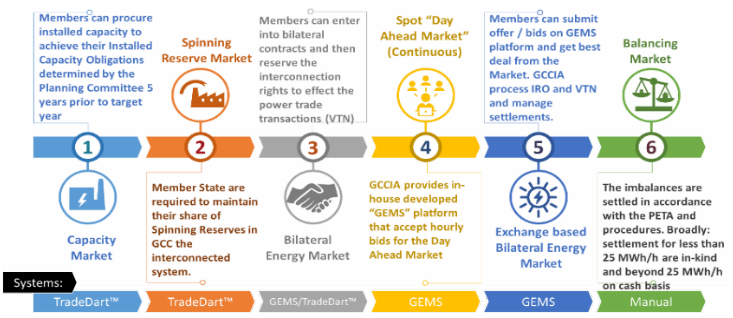

Figure 4: GCC region's market trade activity summary.

DR Programs and Avoided Costs

Under emergency conditions, a program was introduced for Member States to respond to any interruption by employing High Level Consumers for load interruption/curtailment at the state level. The program is dispatchable from the Interconnector Control Centre (ICC). Total energy support to all states during the 2020 year was 5,246 MWh. The average value for the Value of Lost Load (VoLL) was $2,539/MWh. The estimated avoided cost is as illustrated in Table 2 below, where it is equal to $11.78 million (U.S.) in year 2020.

	VoLL			
Country	**2018**	**2019**	**2020**	**2021**
UAE	6,124	6,496	3,038	2,392
Bahrain	1,968	2,107	2,177	1,859
KSA	5,630	6,483	2,187	1,873
Oman	2,055	2,348	2,279	1,803
Qatar	3,549	3,886	3,768	2,945
Kuwait	1,627	1,861	1,783	1,308
GCC Total	20,954	23,180	15,233	12,180

Table 2: Value of Lost Load (VoLL).

CONCLUSIONS

Both electricity producing DER resources (e.g., energy storage, behind-the-meter DG) as well as demand responsive loads are being triggered in DR programs to support a variety of power system functions. DR programs help to avoid costs that otherwise would be incurred in the business of power system capacity expansion, electricity generation, transmission, delivery, and customer service. How avoided costs are expressed depends on the application for which DR is employed. For example, avoided cost of DR employed for balancing energy is typically expressed in $/MWh, for reserve in $/MW per time period of reserve provision, economic dispatch in $/MWh, and capacity in $/kW/year.

The nature of the regional market and industry structure determines to a large extent which stakeholder types are motivated to employ DR for various purposes, and whether those purposes achieve primarily financial benefits to specific parties or economic benefits to all customers as well as specific parties. Although avoided cost outcomes and the stakeholders that achieve avoided costs with DR depend on regional factors, some similarities can be noted across surveyed regions. These include:

a) A distribution company's DR cost impact is capacity related (not energy).
b) Generation companies assess an energy value for DR (e.g., avoided fuel, variable operations and maintenance costs). The value of avoided energy from DR to market is essentially the variable cost (fuel cost). Consequently, DR programs focus on short-run marginal cost of generation, as the notional expression of avoided cost, although DR could also be employed to impact generation planning in the long-term.

c) A long run implication of DR is a reduction or deferral of peak capacity addition (e.g., generation, transmission and/or distribution). If DR is in place for a long period to displace peak demand reliably, DR displaces peaking capacity needed in the market.
d) As a physical hedge, DR can reduce the volume of energy needed to be procured by an energy retailer (e.g., at peak price), thereby reducing energy purchase costs. This is key since energy retailers in many regions sell electric service at a fixed rate but procure energy at a variable price.
e) DR can also be employed for ancillary services and real-time balancing energy to reduce deviation changes when actual power usage deviates from that scheduled.
f) DR may increase customer service interaction costs involved in administering DR programs. Nevertheless, energy retailers and third-party aggregators have DR program offerings as a business differentiator and/or to improve customer service satisfaction.
g) DR can also avoid financial market costs through lowering the clearing price of wholesale energy, by reducing the need for energy with DR. This differs from economic costs avoided (e.g., avoiding cost of burning natural gas, when reducing the need for energy with DR).

FUTURE WORK

DR can flexibly be employed to support multiple power system functions, as illustrated through 13 program examples from 5 regions, each with multiple applications for DR. Future work includes elaboration on technological, operational, and programmatic considerations when managing DER/DR technologies to provide flexible DR in actual implementations designed for avoided cost capture. Besides technical advances, program advances are key for overcoming customer engagement challenges when aggregating and integrating demand-side technologies to capture avoided cost. Key customer sectors and technologies amenable to flexible DR are also important topics for elaboration. For example, customer sectors with inherent energy storage (e.g., water pumping systems, refrigeration systems) may be particularly well suited for engagement. Identifying and addressing economic incentives is also key for engaging customers and overcoming disincentives which may stem from historic rate structures.

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