



International Demand Response Practices: Implications for Russia

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Energy Centre
Moscow School of Management



Brief overview of three cases considered

	USA - PJM	UK - National Grid	Ontario - IESO
Installed Generation Capacity (GW)	186	106,1 (72,3*)	37,5
Peak Load (GW)	165	50,4	23,2
Electricity Volume (GWh)	806 546	333 000	137 400
DR volume (GW)	11,3	1,4	0,8
Ratio of DR to Peak load	6,8%	2,8%	3,5%
Participation of DR in the markets	Capacity market, Energy market, Ancillary services market	Capacity market	Dedicated demand response auction
Time of considered programs functioning	13 years	5 years	5 years

*) Declared net capacity

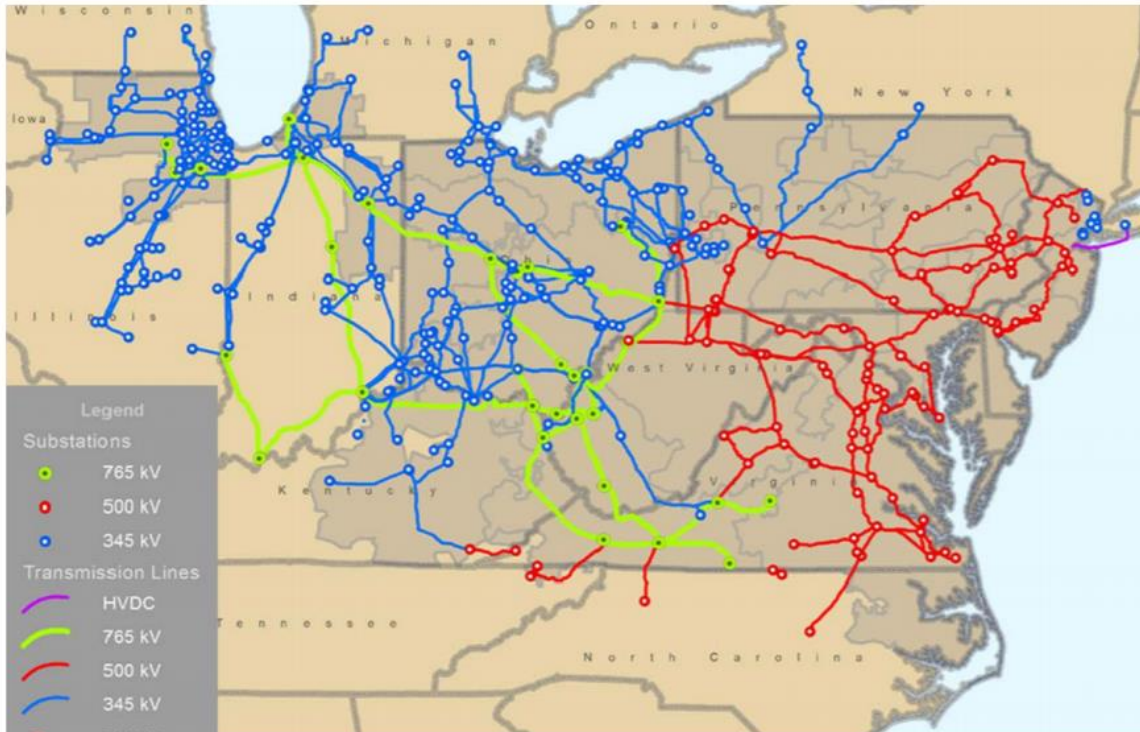
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Introduction and brief history

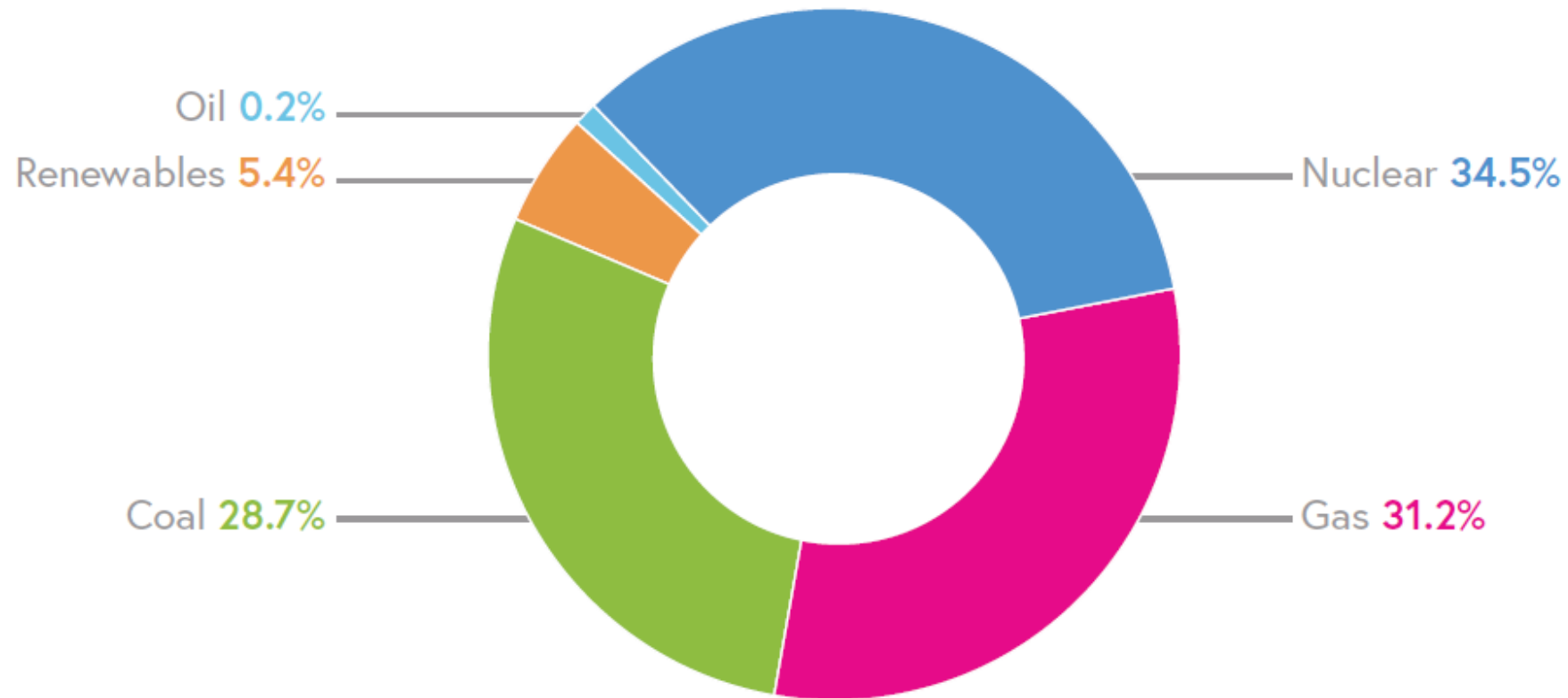
- PJM energy system has certain similar characteristics to the Russian energy system (e.g. on the peak load level).
- Current state of the PJM demand response programs results from 13 years of experiments and developments.
- During first years this program has been operated in a pilot mode (volumes did not exceed 2 GW), while during 2008-2010 it was gradually expanded and in 2011 the DR resources exceeded 10 GW.
- Initially the program was administered separately from the energy and capacity markets but later it was integrated.
- Main ELPR program was covering only peak summer months but recently its coverage was expanded for the entire year.

PJM - general characteristics



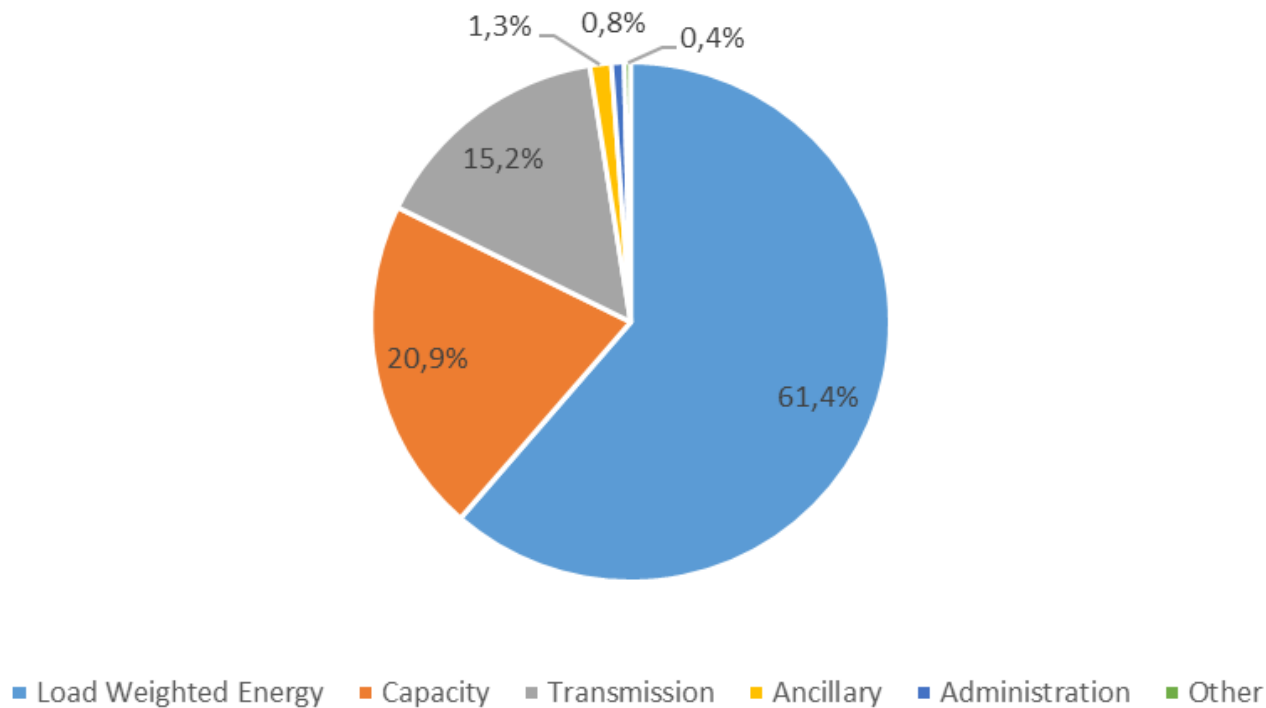
- PJM Interconnection is a regional transmission organization (RTO) that operates a competitive wholesale electricity market and manages the high-voltage electricity grid in all or parts of 13 states of the US and District of Columbia.
- General characteristics of the energy system:
 - Final consumers: 65 mln people
 - Installed generation capacity: 186 GW
 - Peak load: slightly over 165 GW ((140 – 165 GW during past 10 years)
 - Electricity volume: 806 546 GWh per year
 - Power transmission lines (overhead): over 135K km
 - Area: 143K square km
 - Annual payments: 49,8 bln USD

Electricity balance structure in 2018



Volume and structure of PJM market

Structure of payments in PJM market (2018)



- Total volume of payments in PJM in 2018 was equal to 49,3 billion US dollars
- This includes payment for energy, capacity, transmission services, ancillary services, administration costs

Change in average electricity wholesale price in PJM

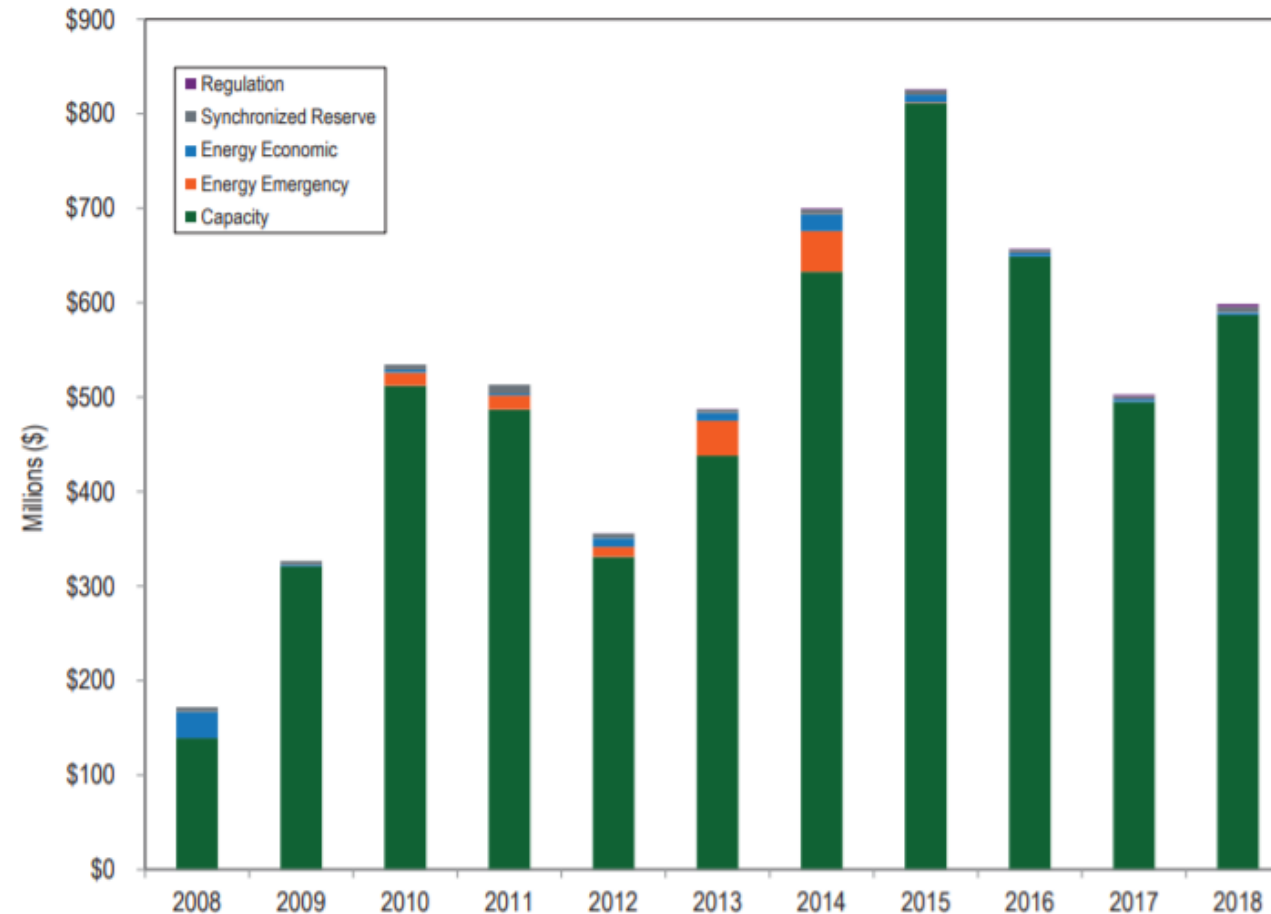


- Consumers were able to take advantage of decreasing gas prices and competition between various suppliers
- PJM market allows consumers to save over 2,3 bln USD per year by integrating the most efficient resources, lowering costs and decreasing the need for reserves
- Average wholesale market price includes both the cost to generate electricity and transmission fees

Overview of various demand response programs in PJM

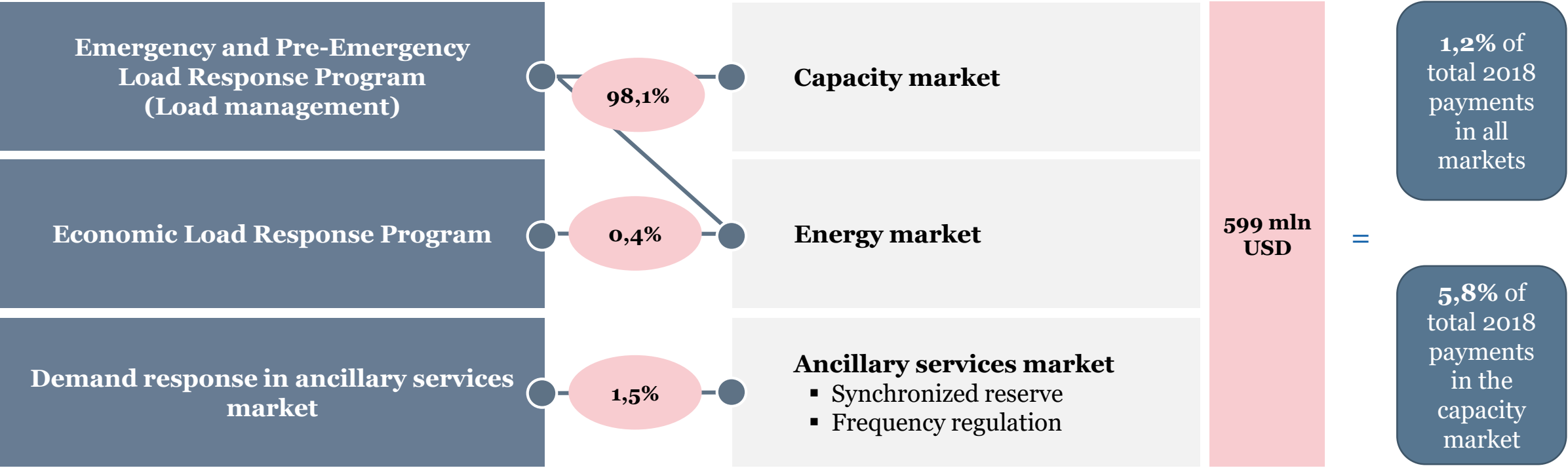
	Emergency and Pre-Emergency Load Response Program			Economic Load Response Program	Price Responsive Demand
	Load Management (LM)				
Market	Capacity Only	Capacity and Energy	Energy Only	Energy Only	Capacity Only
Capacity Market	DR cleared in RPM	DR cleared in RPM	Not included in RPM	Not included in RPM	PRD cleared in RPM
Dispatch Requirement	Mandatory Curtailment	Mandatory Curtailment	Voluntary Curtailment	Dispatched Curtailment	Price Threshold
Penalties	RPM event or test compliance penalties	RPM event or test compliance penalties	NA	NA	RPM event or test compliance penalties
Capacity Payments	Capacity payments based on RPM clearing price	Capacity payments based on RPM clearing price	NA	NA	Avoided capacity costs
Energy Payments	No energy payment	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment during PJM declared Emergency Event mandatory curtailments.	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment only for voluntary curtailments.	Energy payment based on full LMP. Energy payment for hours of dispatched curtailment.	NA

Demand response revenue distribution across various markets

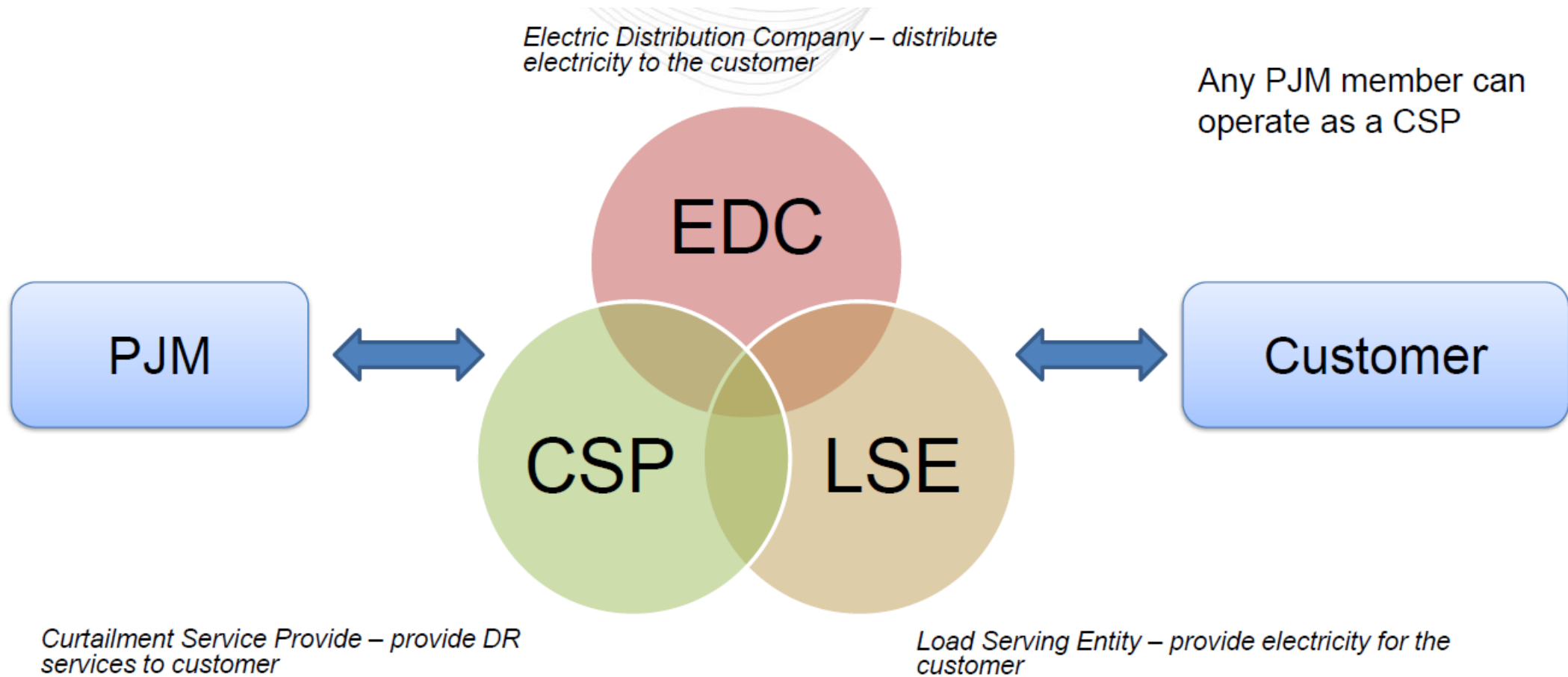


Demand response programs participation in various market segments

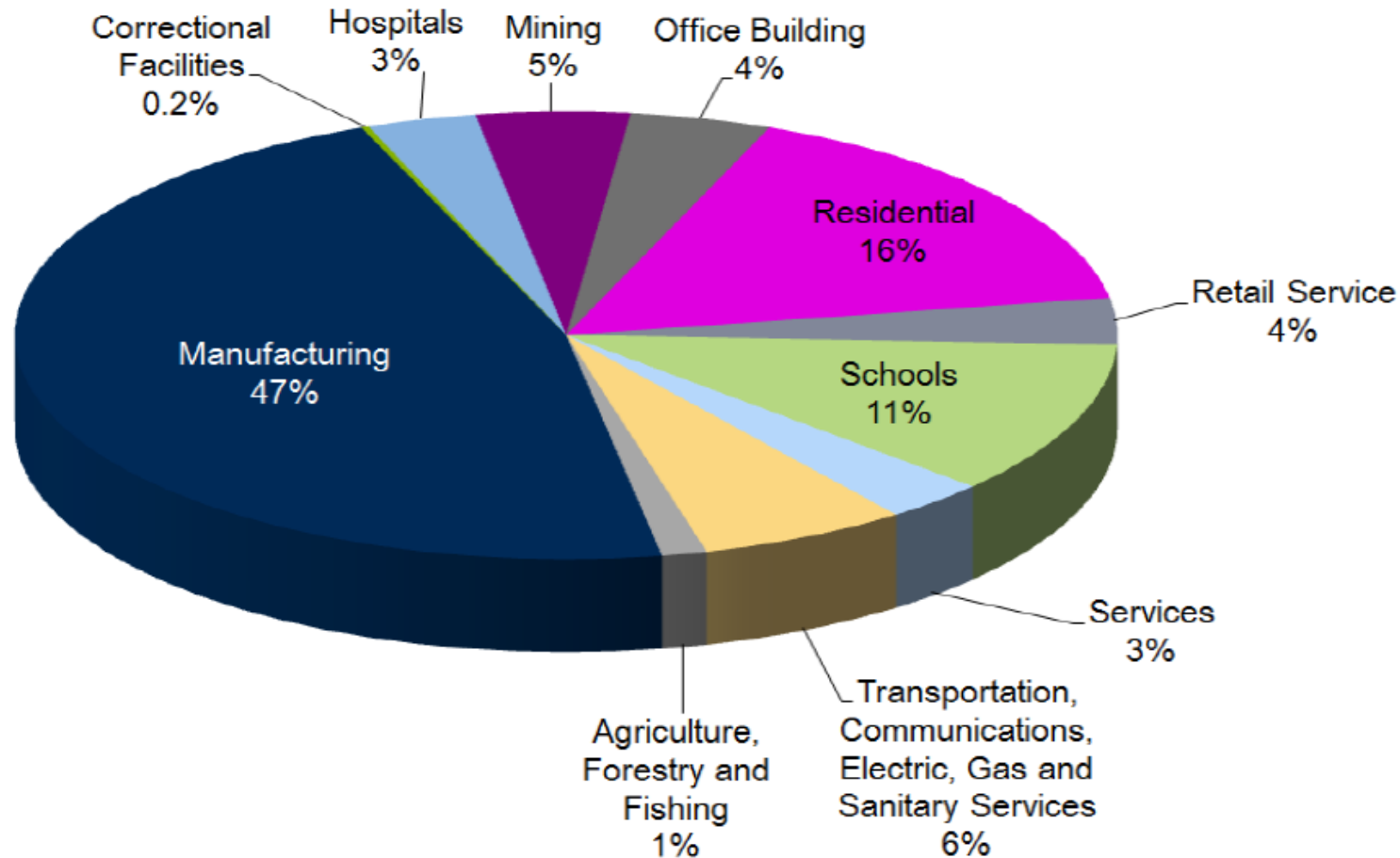
Demand Response is a voluntary PJM program that compensates end-use (retail) customers for reducing their electricity use (load), when requested by PJM, during periods of high power prices or when the reliability of the grid is threatened.



Wholesale market role model



Demand response services providers for 2019/20 year of supply



Q&A #1

Question:

Would it be fair to say that DR resources are mainly used for emergency reserve purposes?

In other words - they are rarely used for actual peak consumption shaving in order to decrease the wholesale energy prices in the market during peaks?

Answer:

For ELRP (Emergency Load Response Program), that is correct—it is mainly used for emergency reserves. The Economic DR program, in which we have only a small handful of customers registered due to relatively low wholesale energy market pricing in PJM in recent years, somewhat serves the purpose of “peak shaving”. However, those customers are acting more like traditional generation resources, as they are simply trying to collect energy market revenues for themselves—there is likely a second order effect of lowering wholesale energy pricing, which is great for those customers and all load as a whole, but that is not the primary driver for those customers’ decision to participate in this program. Additionally, some states in PJM’s territory (e.g. Pennsylvania) have or are considering state-based DR programs geared exclusively towards peak-shaving. The goal of these programs is generally to lower PJM’s load forecasts for the transmission zones in those states, thereby lowering the volume of capacity procured, thereby lowering capacity costs to ratepayers. But from a PJM wholesale market perspective, there is no program where the aim is to peak shave and/or lower energy market pricing.

Q&A #2

Question:

Is there any government policy to support and expand Demand response within PJM – or is it a pure economic competition with other resources (first of all – conventional generators)?

Answer:

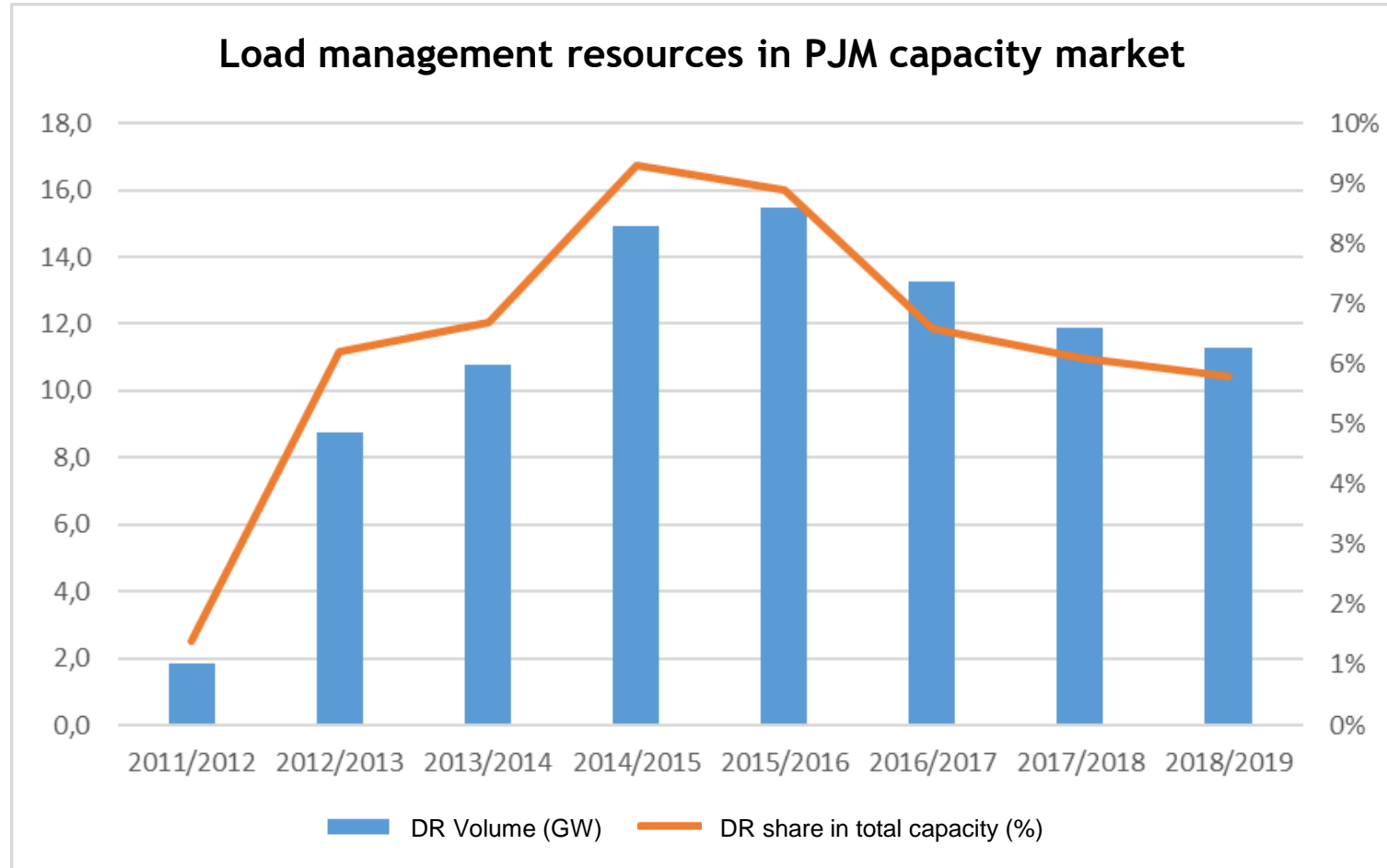
The main implicit government support for DR (applies to all of US, not just PJM) is that DR earnings are viewed as “rebates” on retail customers’ electric bills, and so customers’ DR earnings are not subject to federal income tax.

As for explicit government policy/support, Congress has passed various pieces of legislation over the years that have instructed FERC to promulgate Orders to facilitate DR participation in wholesale markets on an equitable “playing field” with conventional generation, e.g. FERC Order 745 and Order 841, to name a few.

Detailed overview of DR programs in PJM

1. **Emergency and Pre-Emergency Load Response Program (Load management)**
2. Economic Load Response Program
3. Price Responsive Demand

Load management in PJM capacity market



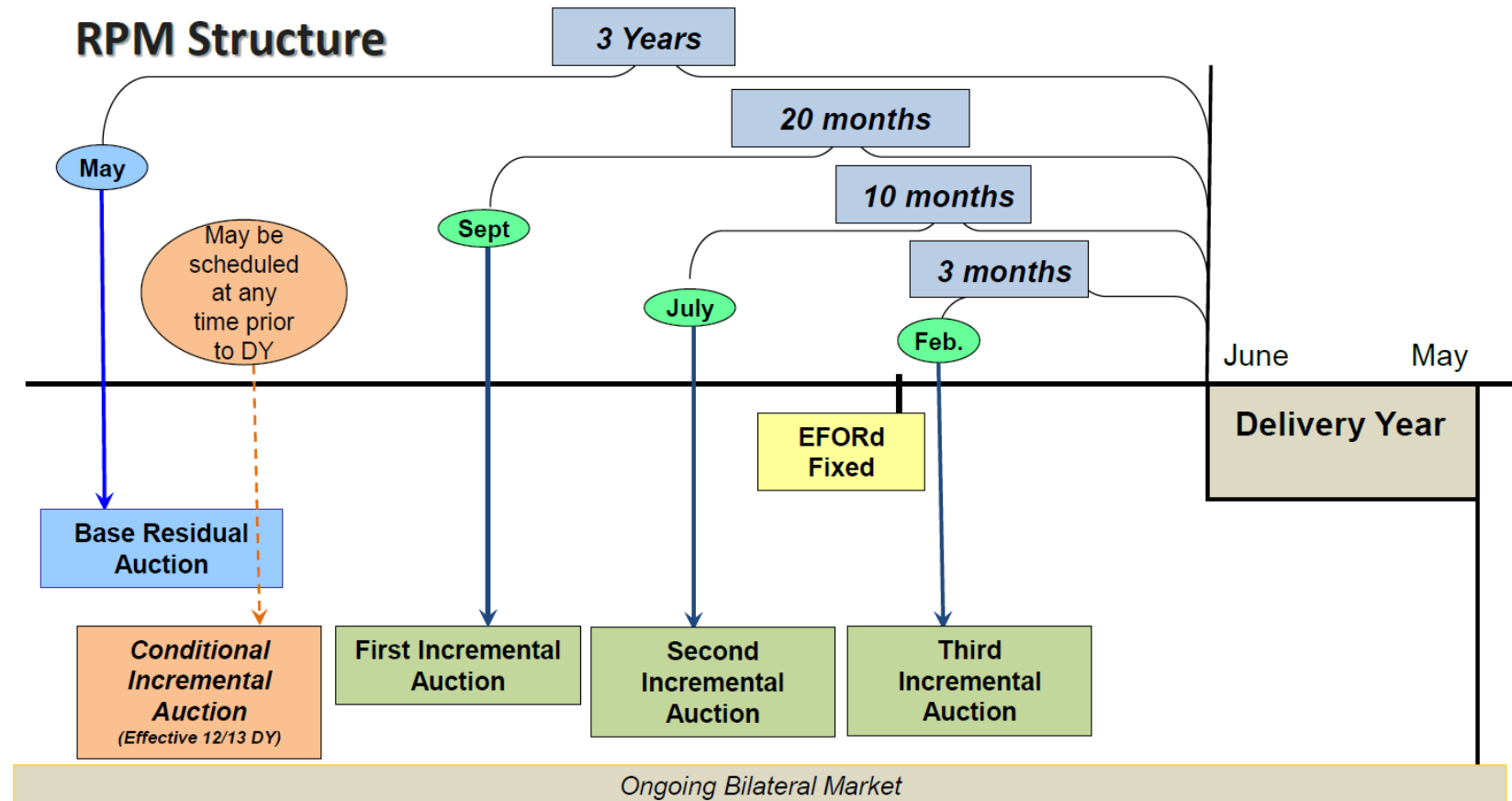
What kind of revenue can consumer expect from capacity market?

- Revenue size will depend on the number of MWs cleared at capacity market auction and on the clearing price.
- Although price will become known after auction results are published, cash flow is generated during delivery year.
- Historically clearing prices have been between 40 and 240 USD per MW-day depending on the delivery year and resource location.

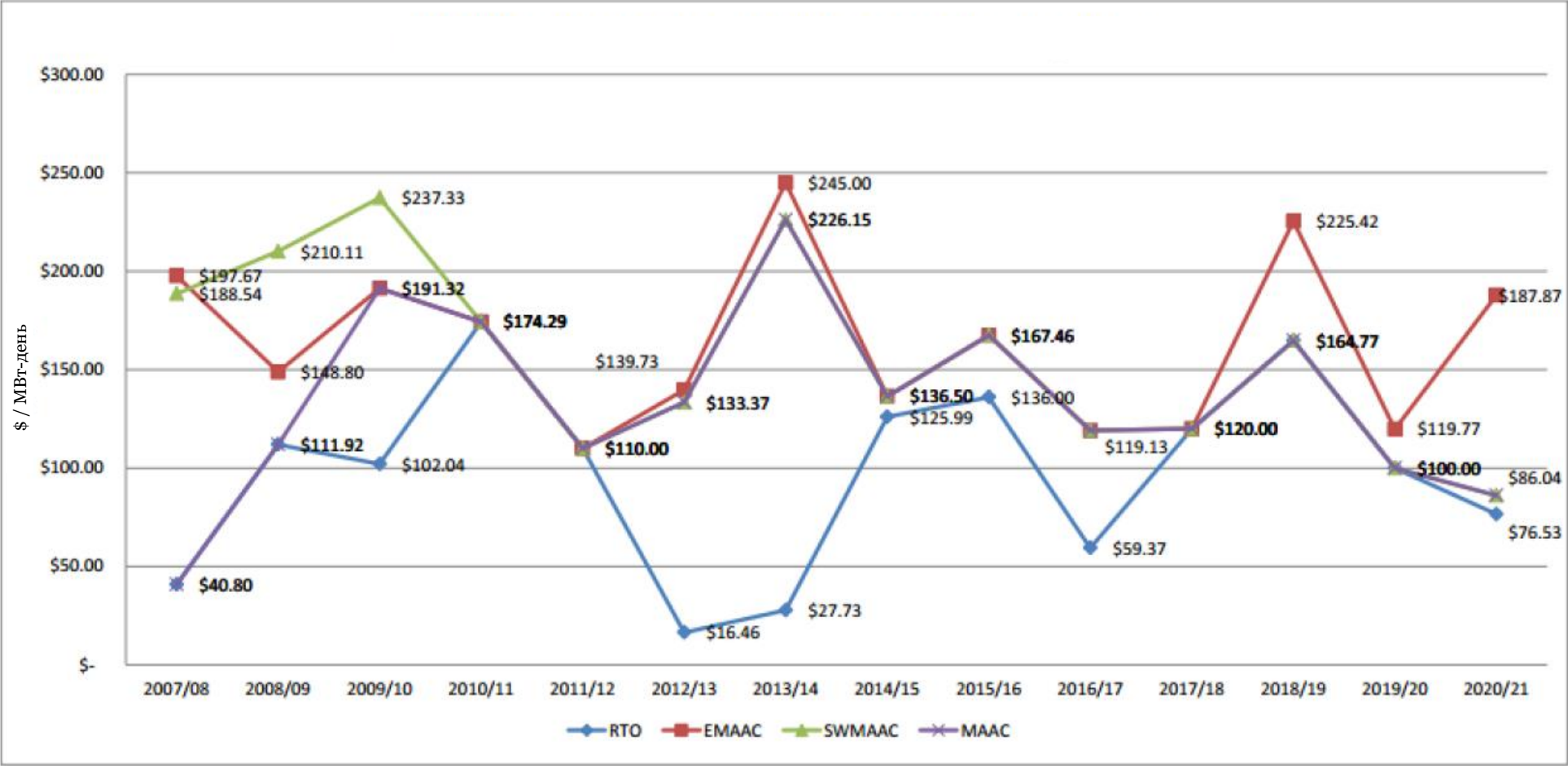
Example:

- Aggregator's application for 20 MW is cleared in the auction with price of 100 USD per MW-day and it supplies these 20 MW.
- Revenue size $20 * 100 * 365 = \$730K$
- This revenue is accrued on a daily basis and is paid out monthly until the transfer to weekly scheme is completed – after that it will be paid every week.

Auctions timeline in the capacity market



Historical prices in base auctions



Q&A #3

Question:

Why are capacity prices are so volatile and the range is so wide across years and also across areas within PJM (16 – 245 usd per MW-day)?

Answer:

The short answer is that PJM has made numerous changes to various parameters used in the capacity auction over the past 10 years, including (1) the shape of demand curve used (convex vs. concave), (2) the inclusion of DR in the auctions (i.e. after ILR was retired after 2011/12, 9-12 GW of DR resources were included in the supply stack, significantly driving down pricing for 2012/13 and 2013/14), (3) the minimum reserve margin target, (4) new transmission zones joining PJM, (5) which zones are modelled as their own “LDA” (locational deliverability area), and (6) changing the penalty structure of the capacity product (e.g. the introduction of “Capacity Performance” for the 2018/19 BRA, when the market overreacted and prices abnormally high).

Additionally, the cost structure for coal and gas generation has shifted significantly over that time period as well, and the PJM-imposed changes often resulted in coal and gas switching from being the marginal offers in the capacity market from one year to the next. Lastly, I will note that in addition to the base RTO price, PJM’s use of LDA’s allow certain constrained regions of the grid to clear at a higher price as a signal for the need for more investment in capacity resources. With the exception of 2 anomalous years (2012/13 and 2013/14), RTO pricing has generally been in the \$60-140/MW-day range over the past 10 years. But more constrained LDAs, like EMAAC (which represents heavy load centers along the East Coast, including densely-populated areas like New Jersey and eastern Pennsylvania) have generally higher pricing and more volatility by virtue of there being fewer capacity resources available in those regions, and so some resource owners have been able to exercise quasi-monopolistic powers in some years there. PJM’s capacity market (and DR participation in the capacity market in particular) was very much going through “growing pains” in the first several years, so pricing shocks (driven by supply and/or demand) were common. One possible way to mitigate this to allow for multi-year procurement, which is something that ISO-NE allows for new entrant resources, where owners of new resources can opt to clear a commitment at a single market price for anywhere from 1 to 7 years.

CP Demand Resource Transition

Requirement	(Today) Limited DR (15/16 – 17/18)	(Today) Extended Summer DR (15/16 – 17/18)	(Today) Annual DR (16/17 – 17/18)	(CP) Base Capacity DR (18/19 & 19/20 DY only)	(CP) Capacity Performance DR (16/17 DY & beyond)	(CP) Summer Period DR (20/21 and beyond)
Availability	Non-NERC holiday weekday, June – Sept	June – Oct & May	Any day during DY*	June - Sep	Any day during DY*	June – Oct & May
Maximum Number of Interruptions	10 interruptions	Unlimited	Unlimited	Unlimited	Unlimited	Unlimited
Hours of Day Required to Respond (Hours in EPT)	12:00 PM – 8:00 PM	10:00 AM – 10:00 PM	June – Oct & May: 10 AM – 10 PM Nov. – April: 6 AM- 9 PM	10:00 AM – 10:00 PM	June – Oct. & May: 10 AM – 10 PM Nov. – April: 6 AM- 9 PM	10:00 AM – 10:00 PM
Maximum Duration of Interruption	6 Hours	10 Hours	June – Oct : 12 hours Nov – April: 15 hours	10 Hours	June – Oct : 12 hours Nov – April: 15 hours	12 Hours

Vast majority of dispatches set off by weather events; event risk has shifted from summer to off-peak months

Event Count by Zone, 2005-2019

Zone	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
AECO	3	2	1	0	0	1	0	0	1	7	0	0	0	0	0
AEP	0	0	0	0	0	1	0	1	3	4	0	0	0	0	1
APS	0	0	0	0	0	2	0	0	0	7	0	0	0	0	0
ATSI	0	0	0	0	0	0	0	0	5	4	0	0	0	0	0
BGE	3	2	1	0	0	3	1	1	1	8	0	0	0	0	1
COMED	0	0	0	0	0	3	0	0	0	4	0	0	0	0	0
DAY	0	0	0	0	0	0	0	0	0	4	0	0	0	0	0
DEOK	0	0	0	0	0	0	0	0	0	4	0	0	0	0	0
DOM	0	0	1	0	0	1	0	1	1	7	0	0	0	0	1
DPL	2	2	1	0	0	1	1	1	1	7	0	0	0	0	0
DUQ	0	0	0	0	0	0	1	0	1	4	0	0	0	0	0
JCPL	3	2	1	0	0	1	1	1	1	7	0	0	0	0	0
METED	3	2	1	0	0	0	1	0	1	7	0	0	0	0	0
PECO	3	2	1	0	0	1	1	1	2	7	0	0	0	0	0
PENELEC	3	2	1	0	0	0	0	1	1	7	2	0	0	0	0
PEPCO	3	2	1	0	0	4	0	1	1	8	0	0	0	0	1
PPL	3	2	1	0	0	0	0	0	2	7	0	0	0	0	0
PSEG	3	2	1	0	0	1	0	0	1	7	0	0	0	0	0
RECO	3	2	1	0	0	0	0	0	1	7	0	0	0	0	0

Key inflection point for PJM as its generation mix relied less on coal and more on gas units

Pre-2007, DR did not receive capacity payments; "voluntary participation"

Majority of the dispatches occurred in January and one event in March during the 2014 North American Cold Wave (Polar Vortex)

Weather driven capacity shortages drove the events in 2017 and from 2010 to 2014. In each year, all the notable "high-impact" dispatches coincided with a heat wave or was preceded by a "hot weather alert"

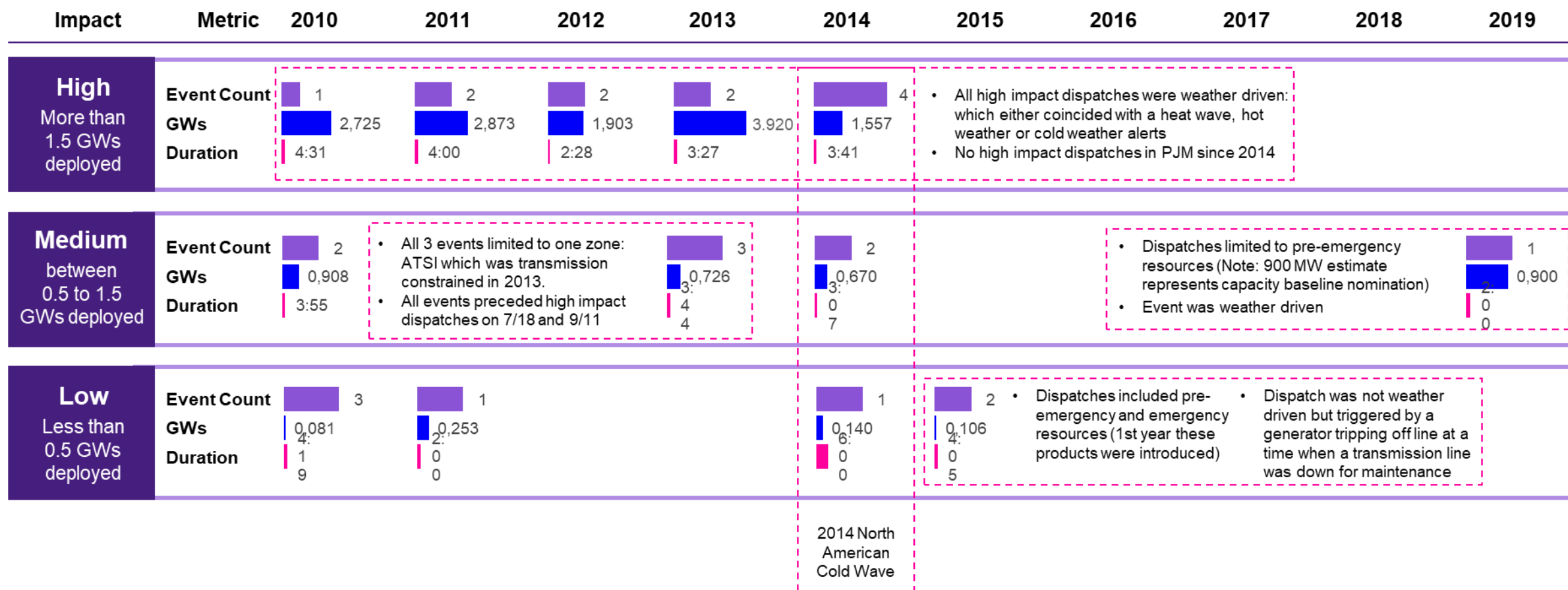
The only 2 deployments that occurred on a mild day and was local in nature; a transmission line was down for maintenance and a key generation unit tripped off-line

43 GWs of gen outages and unusually hot weather in October (Washington, DC, for example, surpassed an all-time monthly high temperature record that hadn't been broken since 1941) triggered the event

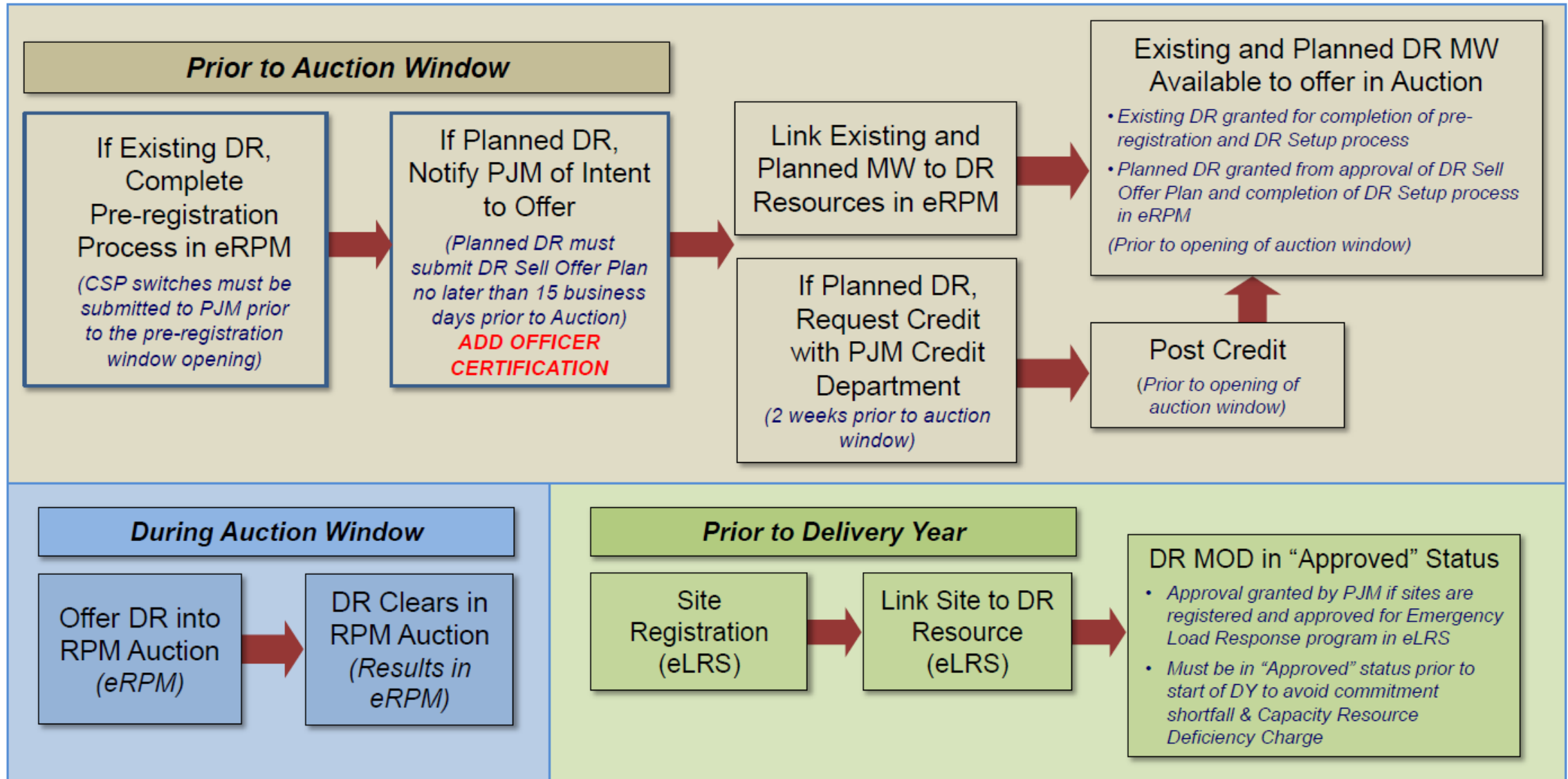
Great majority of dispatches prior to 2014 occurred between June to September, with a few events in 2011 occurring in late May

Since 2014, events only occurred outside of the summer months

Are low to medium impact dispatches more likely in the future?



Steps of DR participation in auctions



Detailed overview of DR programs in PJM

1. Emergency and Pre-Emergency Load Response Program (Load management)
- 2. Economic Load Response Program**
3. Price Responsive Demand

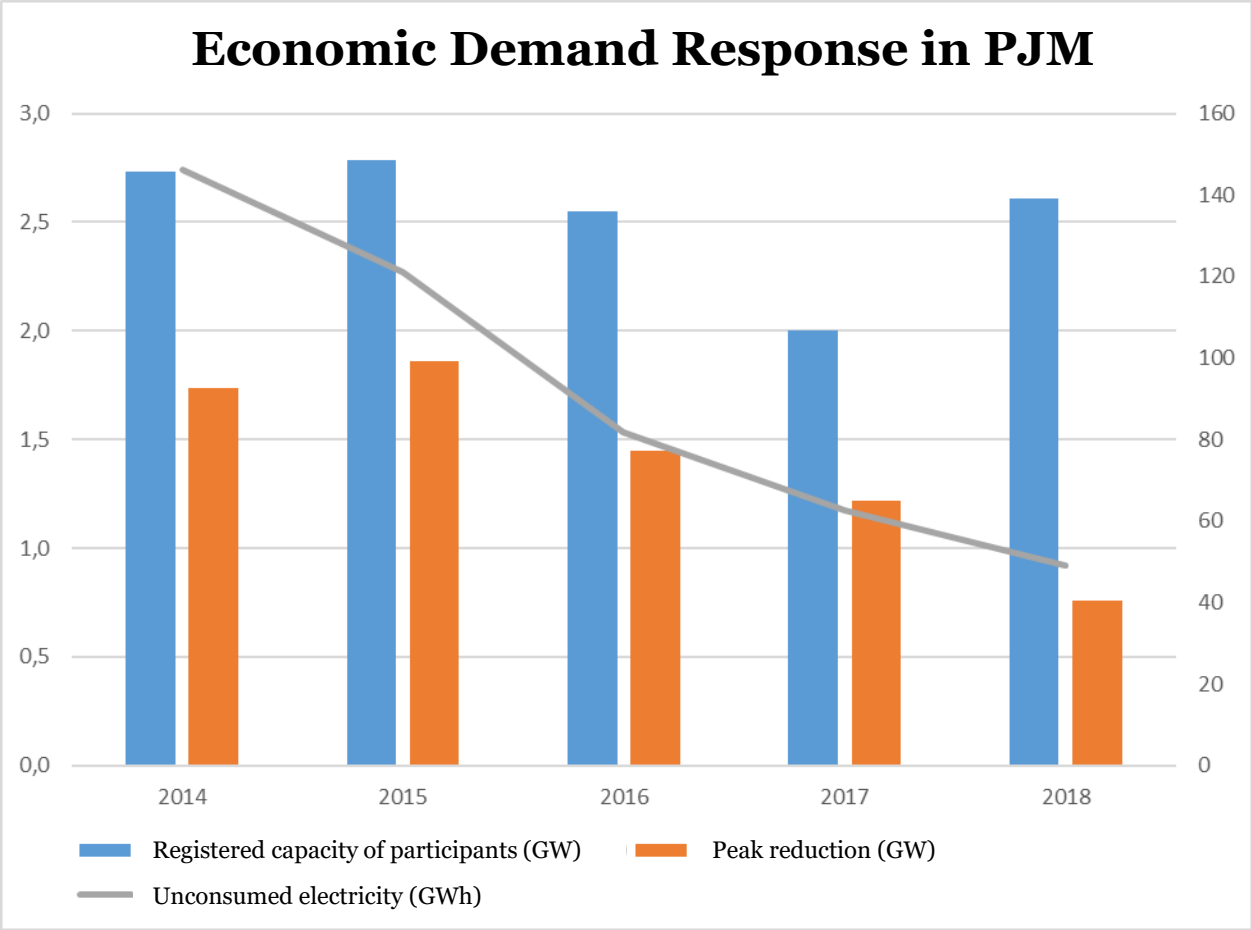
Economic Demand Response (1/2)

- Consumers reduce load at their location when wholesale energy prices (Day Ahead or Real Time) are high and they would not otherwise reduced.
- If reduction would have occurred whether or not cleared, dispatched, or settled by PJM, then reduction does not qualify as Economic DR for payment.
- End Use locations must have interval meters.
- Demand Response registrations may participate in the Day Ahead and/or the Real-Time energy markets.
- Demand Response participation in the energy market is voluntary.
- After a Demand Response registration either clears in the Day-Ahead market or is dispatched in the Real-Time market, a settlement is created and a reduction needs to be calculated in DRHUB.

Economic Demand Response (2/2)

- A Location is the physical site defined by the unique EDC Account Number (typically located on a customer's bill).
- Registrations are required for Market participation. A registration may include one or more location. Registration can be combined with other registrations in a Dispatch Group.
- Dispatch Groups are transferred from DR Hub to Markets Gateway. Dispatch Groups are handled the same way as registrations in Markets Gateway.
- End Use locations must have interval meters. Electric Distribution Company meters or Customer owned meters can be used.
- Metering data is loaded into DR HUB system in XML format or through special templates. All aggregators with certain rights can upload and download metering data for resources under their management. An aggregator can also take decision to allow electric distribution company or load serving entity to upload this data on behalf of an aggregator.
- Curtailment of demand is being measured by the Customer Base Line method (CBL).
- Payment to the aggregator is estimated as a product of the curtailment volume and locational marginal price (if it exceeds the threshold level– Net Benefit Price)

Economic Demand Response in PJM



Source: State of the Market Report for PJM 2018, Monitoring Analytics, LLC

Detailed overview of DR programs in PJM

1. Emergency and Pre-Emergency Load Response Program (Load management)
2. Economic Load Response Program
- 3. Price Responsive Demand**

Price Responsive Demand

- A broader approach to demand response, called price responsive demand, or PRD, is being implemented to expand even more the role of demand resources in PJM.
- It implies the widespread deployment of advanced meters to retail customers that would allow introduction of dynamic retail rates that are linked to wholesale electricity prices.
- In the future, these smart meters will be able to communicate price information to “smart” appliances programmed to automatically change their operation based on the electricity price.
- In price responsive demand consumers will not be paid directly for reductions, but rather will save money on their bills by cutting or shifting their electricity use.
- PJM received and approved PRD plans (~550 MW) for the first time in January 2017 for 2020/2021 Delivery Year and a second time in January 2018 for 2021/2022 Delivery Year.

Q&A #4 (1/3)

Question:

Have you worked with Price Responsive Demand (PRD) and what do you think about it?

Response:

PRD (Price Responsive Demand) became effective in 2012, but there has been zero participation until the 2021/22 BRA. In short, it can attract some limited participation, but it's not a good program concept to attract a lot of participation since the value provided to the customer participant is very limited compared to available wholesale program options that treat DR as a supply-side resource. The only entities to elect PRD for 2021/22 were several utilities who manage mass-market residential DR programs. Those utility programs mostly utilize remote control of air conditioners, which is an inherently summer-only capability to provide DR MW. With PJM's move to a year-round commitment for the new Capacity Performance product, those summer-only DR MW could no longer be monetized as supply-side resources in the capacity market.

Instead, the utilities opted for PRD. Under PRD, DR customers agree to an energy market strike price in \$/MWh, and when RT LMP's rise above that level, they will curtail demand until pricing drops below the strike price again. PJM's load forecast model includes modelling of RT LMP's, so they can model the impact to zonal load forecasts (and therefore the overall capacity MW PJM orders procured) when, for example, 1 MW of PRD agrees to a PRD strike price of \$1000/MWh vs. if 1 MW agrees to a strike price of \$800/MWh. PJM then adjusts the demand curve used in the capacity auction downward and to the left, where 1 MW of PRD always results in ≤ 1 MW of reduction to the demand curve (unless a PRD participant elects for a \$0/MWh strike price, which they would be crazy to do).

Q&A #4 (2/3)

Response (cont.):

The primary problem with PRD in PJM is that there is no direct compensation, which is why there has historically been zero participation. The way that some states are implementing PRD for 2021/22 is that they calculate the theoretical capacity savings that result from PJM procuring fewer MW at a lower price (assuming a sloped demand curve is used like in PJM's capacity auction), e.g. \$150 million, and the states/utilities then charge all consumers in those regions for a portion of those savings, e.g. \$50 million, on their utility bills via a “non-bypassable rider”—those \$50 million of collections are then used to fund compensation to the actual PRD participants, with the remaining \$100 MM of savings benefiting all consumers.

This is why all successful DR programs in North America treat DR as a supply-side resource. That treatment ensures direct compensation is possible under any sort of auction framework, achieving comparable treatment with traditional generation resources. Additionally, supply-side treatment aligns real-time operational needs on the grid with real-time economics/incentives. With PRD being based on theory and relying heavily on PJM's load forecast models, it's possible that those ~550 MW of PRD for 2021/22 will never be dispatched or that they will be dispatched for hundreds of hours per year, but both outcomes only provide the same amount of capacity market savings to program participants. There are also avoided energy market costs to consumers, but based on modelling done by several states located in PJM's territory, those avoided costs are very small compared to the capacity savings, and therefore all but the most hardy peak-shaving customers get fatigued, and performance often deteriorates over time.

Q&A #4 (3/3)

Response (cont.):

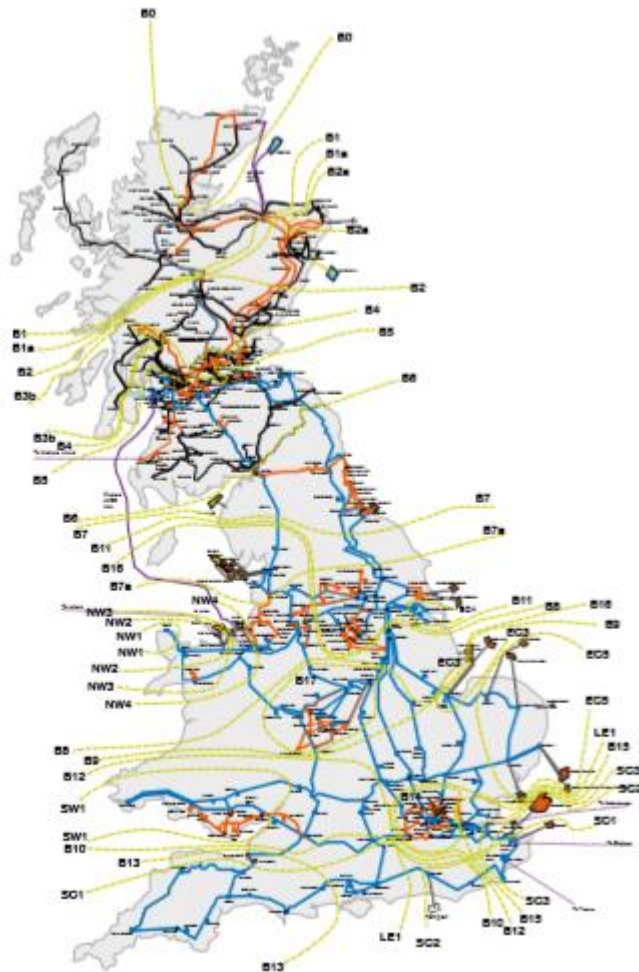
Pennsylvania performed a detail study on this. They were not studying PRD exclusively, but their results can be translated into a PRD program fairly easily, which is something that the state is currently contemplating. The net conclusion of Pennsylvania was that they could cost-effectively pay participants roughly \$15-35k/MW-year in availability payments and \$100-500/MWh in energy payments (depending on the transmission zone), for up to 24 hours of dispatch per summer.

If you compare that to wholesale DR program incentives of \$30-50k/MW-year in availability payments for a minimum 1-hour test per year, plus \$1100-1800/MWh in energy payments for what has historically been 0-6 hours per year on average of emergency dispatches, it makes sense for most customers to stick with the wholesale programs over the state-based peak-shaving program, as PJM is changing the rules to make enrollment in a wholesale program not allowed if a customer is enrolled in a state-based peak-shaving program. Similarly, customers cannot enroll in both PRD and ELRP—each participant can be on only the supply-side or only the demand-side, but not both.

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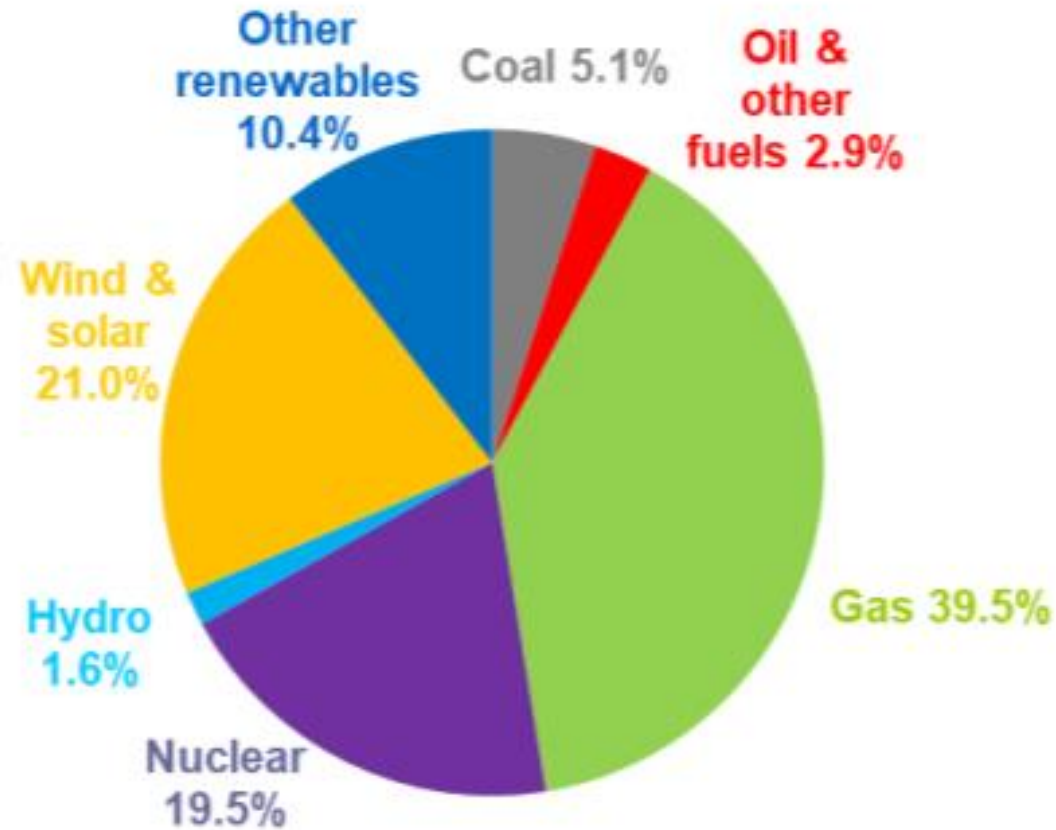
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UK (National Grid) – general characteristics

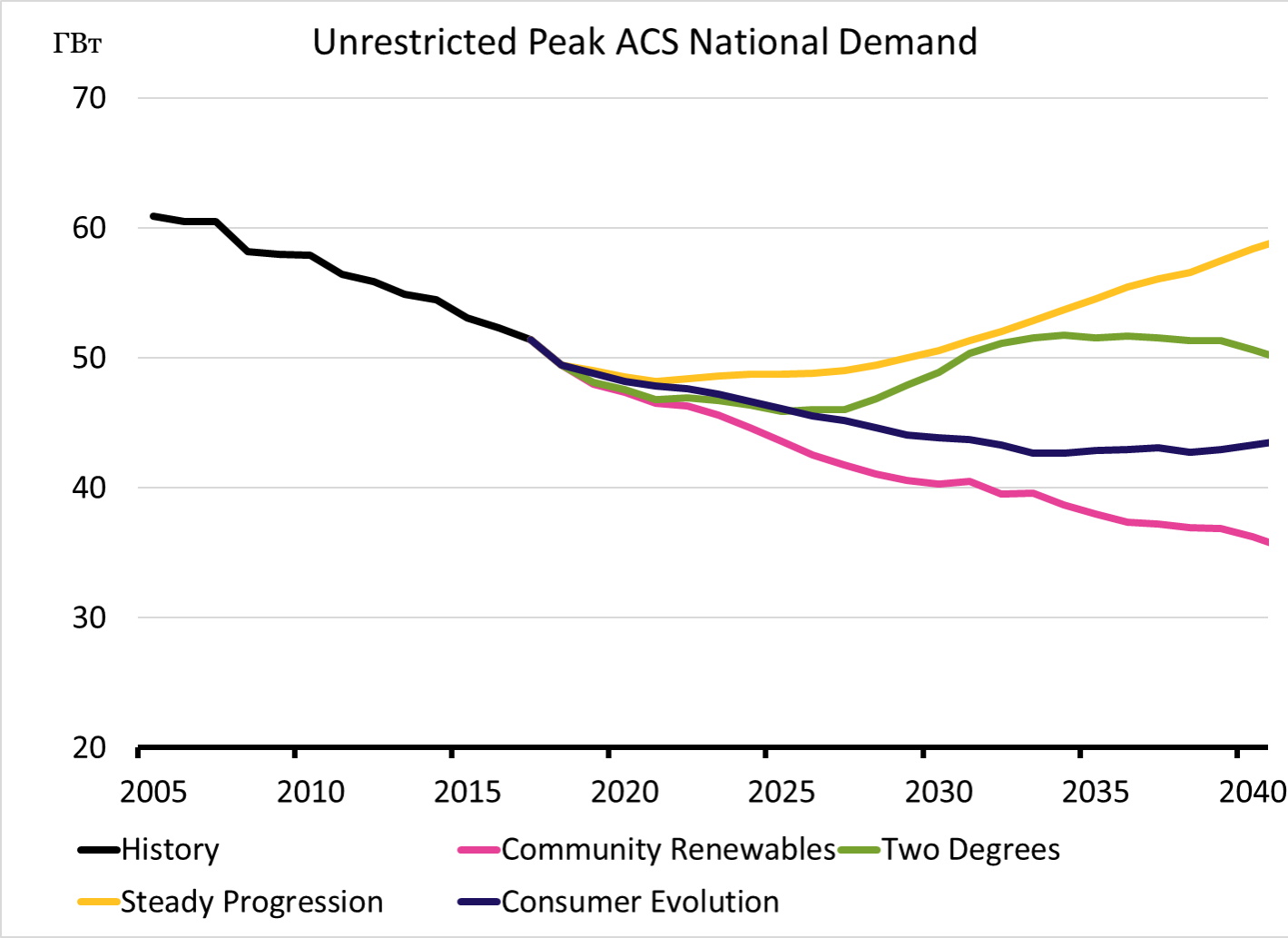


- Country population : over 66 mln people
- System Operator: National Grid Electricity System Operator (NGESO)
- General description of the energy system considered:
 - Covers England, Wales and Scotland, but does not include Northern Ireland
 - Customers: 30,8 mln
 - Installed generation capacity: 106,1 GW
 - Declared net capacity: 72,3 GW
 - Peak load: 50,4 GW
 - Electricity volume: 333 TWh per year
 - Power transmission lines (overhead): over 7,2K km
 - Power transmission lines (cable): 1,4K km
 - Area : 230K square km

Energy balance structure as of 2018



Peak load scenarios



DR as part of the Capacity Market

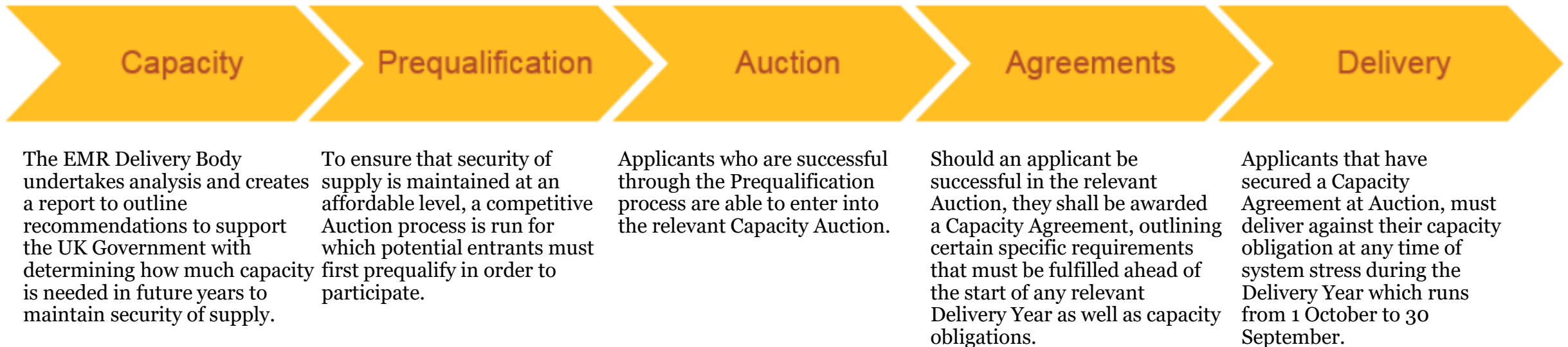
- Demand response programs are part of the capacity market*, which was launched in the UK in 2014 by the Coalition government with objective to attract adequate investments in capacity in order to secure reliable supply of consumers.
- Capacity market compensates generators for being ready to generate electricity during designated time periods, while demand response aggregators – for preparedness to curtail electricity consumption.
- Main capacity auction is being held 4 years in advance of the delivery year (T-4). Auction is divided between participants setting the price (price-makers – new generation and demand response) and participants accepting the price (price-takers – existing generation).
- Auction is designed as the descending-bid auction, where price offered by participants decreases every 30 minutes until supply meets demand. Price-takers are not allowed to exit before the price falls below the price-maker threshold (typically £25/kW-year).
- 1, 3 and 15 year contract durations are available, but the longer duration contracts are explicitly only available to new-build generators. There is a proposal to change this switching to scheme based on capital expenditure thresholds, but in practice it will not help DR to have longer contracts as the thresholds are too high.

*) There is also some DR participation in ancillary services markets, but it's very small compared to the CM

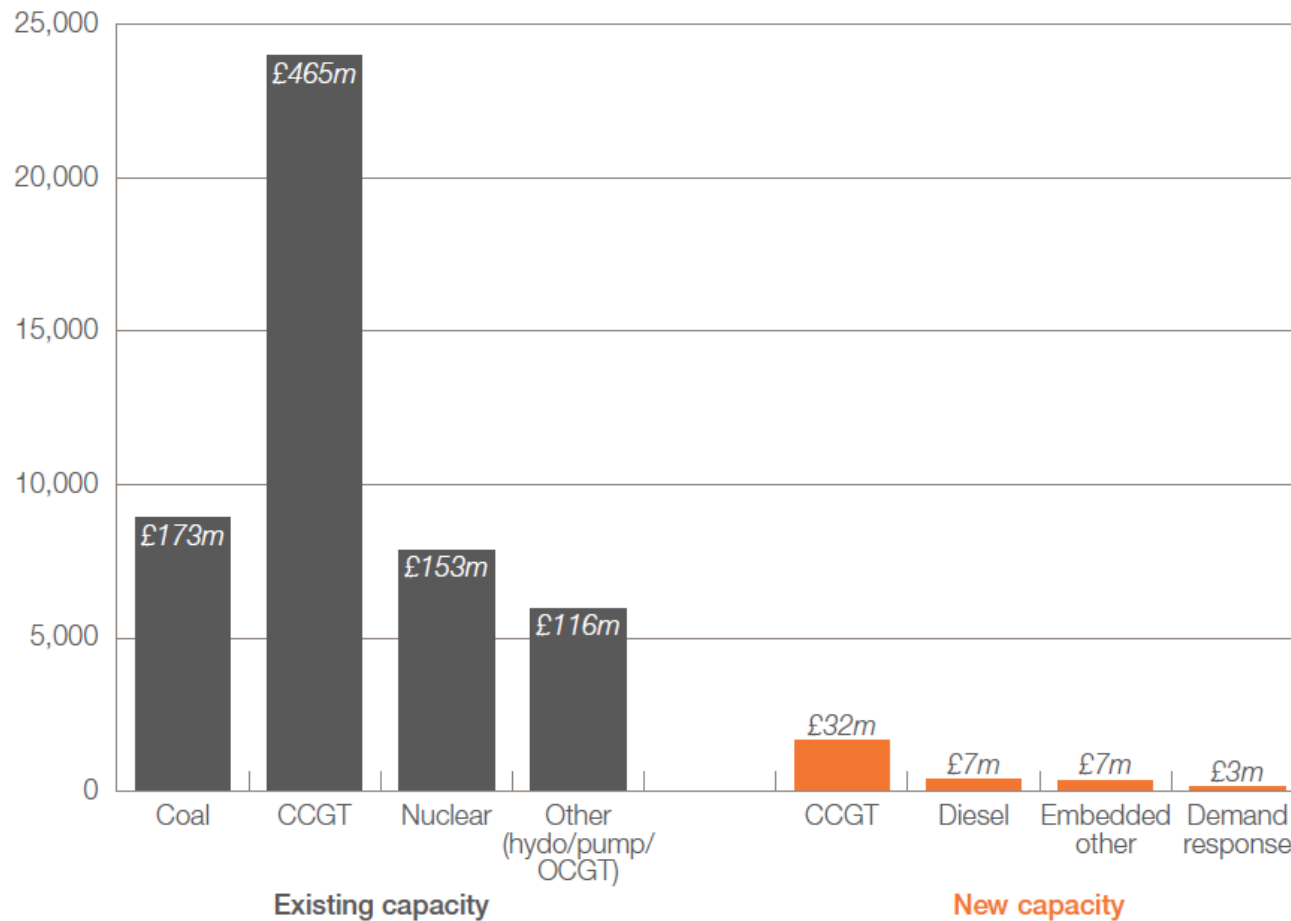
The Capacity Market definition and process

The Capacity Market (CM) is one of the key policies of the Electricity Market Reform programme. The CM aims to ensure the future security of our electricity supply at the lowest cost to consumers.

Key elements of the Capacity Market process

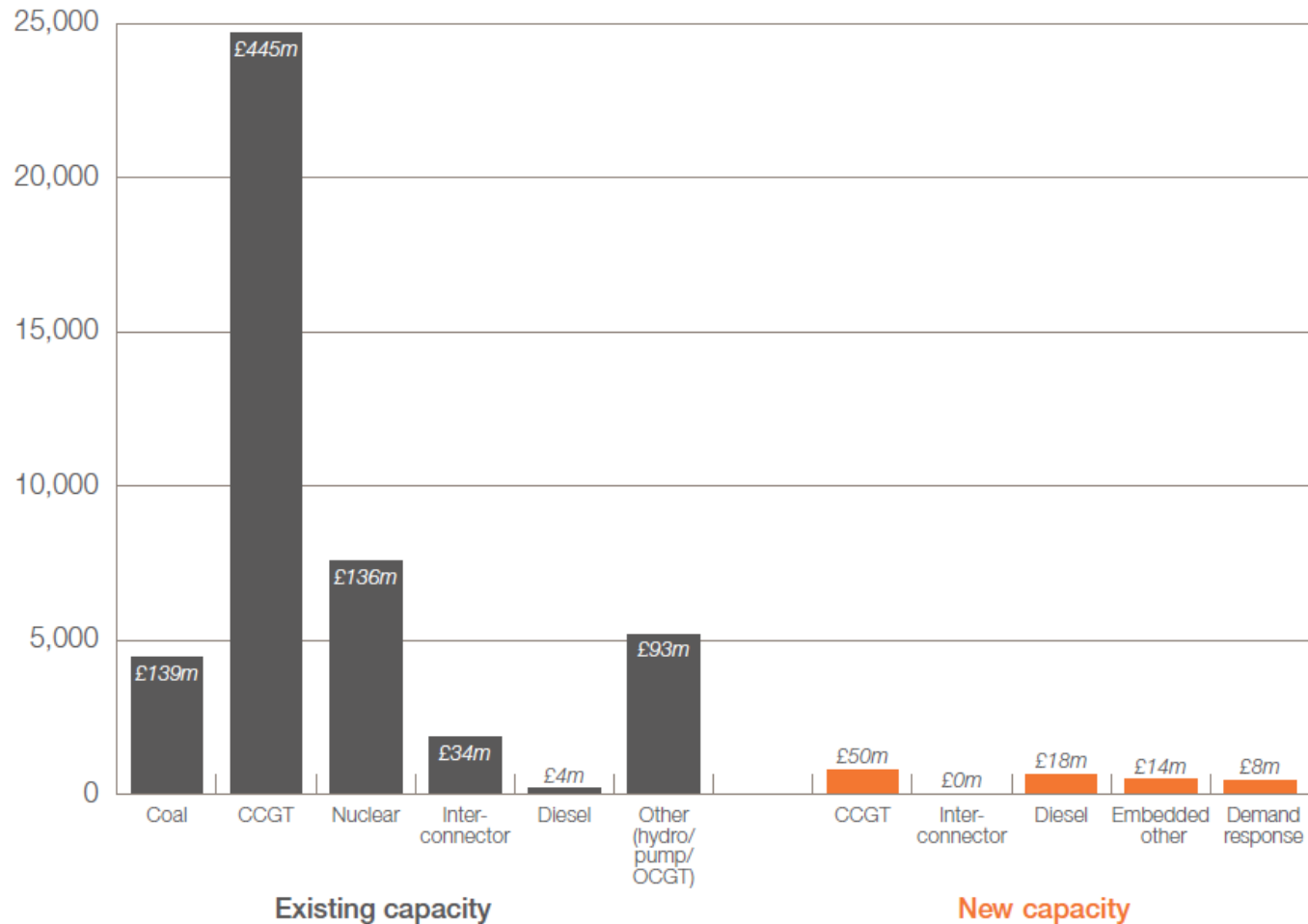


2014 auction results (T-4) for capacity to be supplied in 2018/19



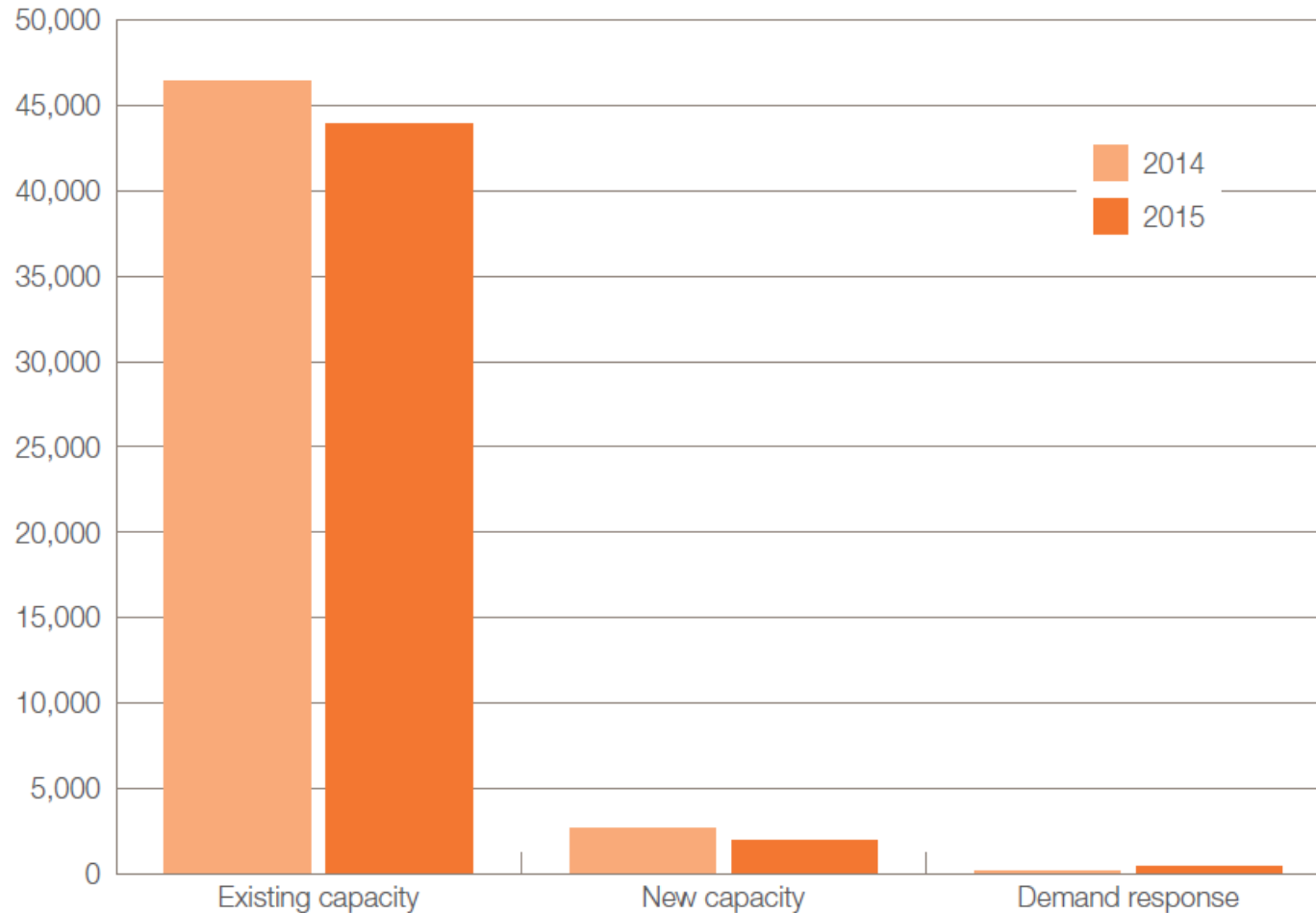
- First auction was held in December of 2014
- Total volume of capacity awarded was equal 49 GW
- Total volume of contracts for 2018/19 was 956 mln pounds
- Capacity clearing price was 19,40 pounds per kW per year
- Only 172 MW out of total volume was awarded to demand response with contracts amounting to 3 mln pounds

2015 auction results (T-4) for capacity to be supplied in 2019/20



- Second auction was held in December of 2015
- Total volume of capacity awarded was equal 46 GW
- Total volume of contracts for 2019/20 was 942 mln pounds
- Capacity clearing price was 18 pounds per kW per year
- 456 MW out of total volume was awarded to demand response with contracts amounting to 8 mln pounds

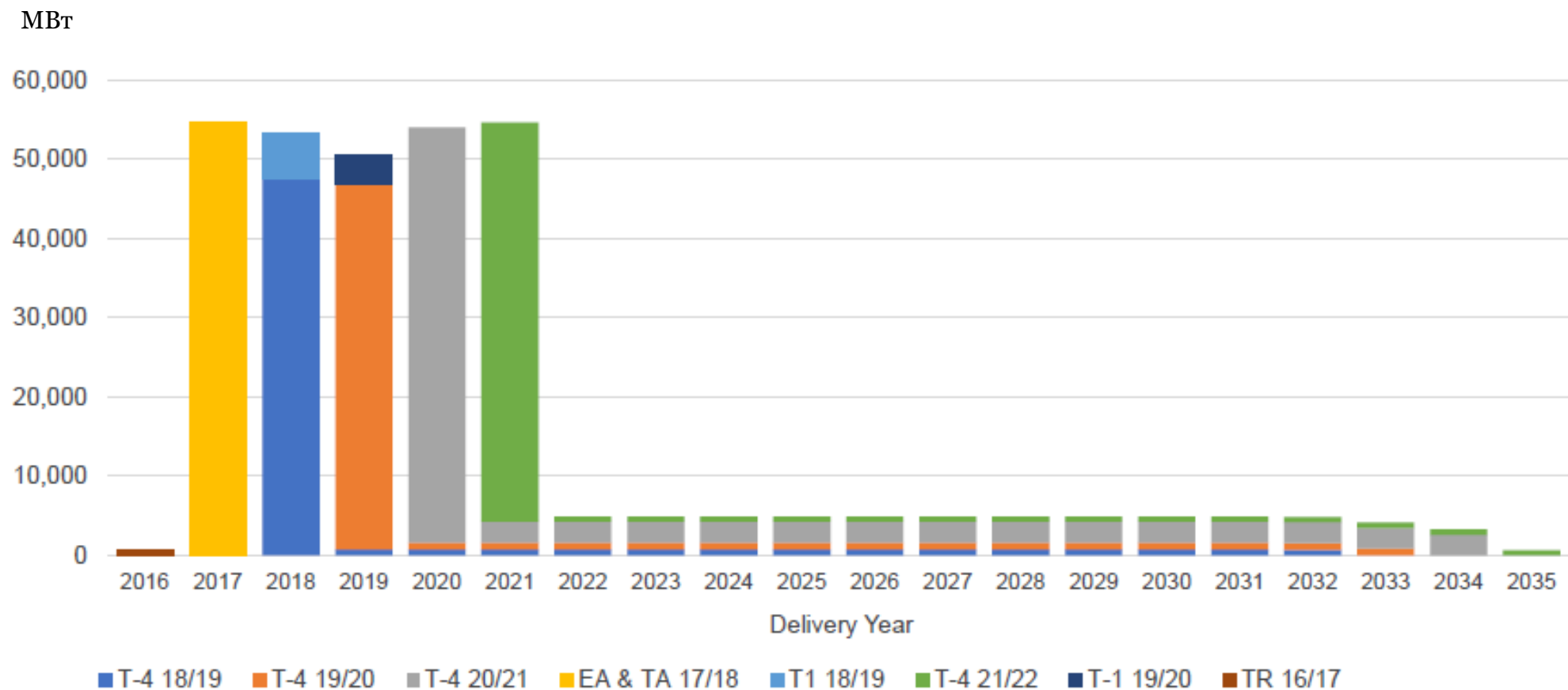
Contracts (MW) awarded in the 2014 and 2015 capacity markets



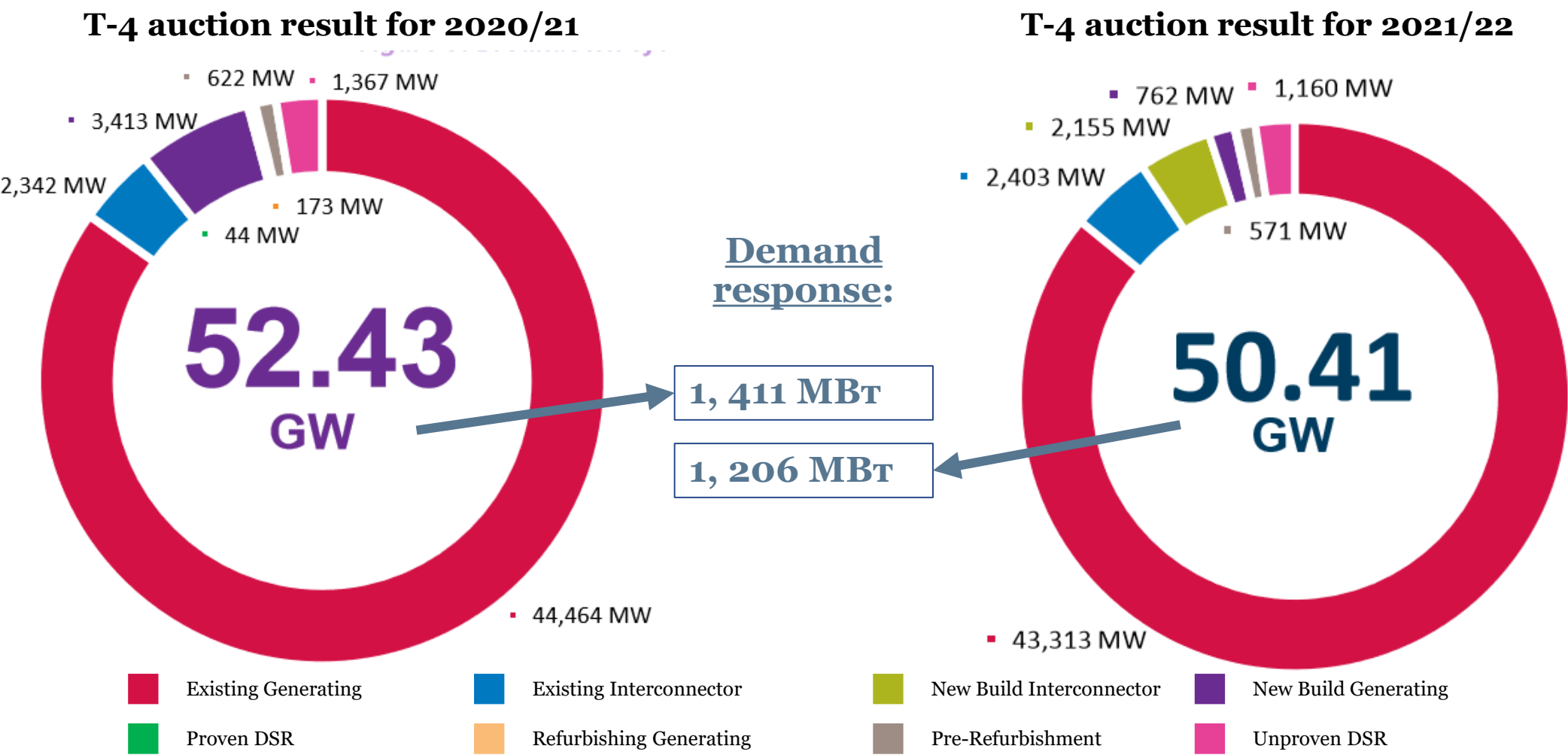
Additional auctions

- Besides main T-4 auctions held in 2014 and 2015, several additional auctions were also conducted:
 - T-1 auction with 2017/2018 deliver year as the Government decided to launch capacity market one year earlier because strategic balancing reserve programme they were relying upon before the start of the capacity market was becoming increasingly expensive.
 - Two transitional T-1 auctions for 2016/17 and 2018/19, first of which was open only for demand response resources and small generation, while the second one was restricted only to DR. The quantities procured in these TA auctions were chosen somewhat arbitrarily, but it was a useful way to build up experience, and also to try out the market mechanisms before using them at full scale.
- The government assumed that DR would participate mainly in the T-1 auctions. This has turned out to be incorrect: most of the volume of DR participation has been in the T-4 auctions, where the prices have been more attractive. The government's mistake was to assume that customers would be unwilling to make commitments years in advance. They neglected to take the role of aggregators into account. In reality, aggregators are willing to take on long-term commitments; the customers they use to fulfil these can change over time.

Capacity delivery contracts by the year of delivery



T-4 auction results for 2020/21 and 2021/22



Source: National Grid ESO

Capacity market suspension



- One of DSR aggregators (Tempus Energy) started to challenge the rules of the capacity markets before the first auction began arguing that they skewed in the favour of fossil fuel generation.
- Based on Tempus's legal challenge in November of 2018 the European Union court annulled the State aid approval for the UK capacity market. The EU has been forced to conduct in-depth investigation of the rules – this process was launched in the February of 2019.
- This resulted in market suspension - payments to existing capacity market contract-holders have been put on hold and there is a risk of reversing previous payments already made if EU does not grant aid approval for the mechanism.
- Auctions were delayed (e.g. T-1 capacity auction for delivery year 2019/20 that was finally held in June of 2019).
- At the end of October of 2019 the European Commission has approved Britain's capacity market scheme following an in-depth investigation into its state aid compliance.
- The Commission said it did not find any evidence that the scheme would put any capacity providers at a disadvantage with respect to their participation in it, nor was it concluded that the mechanism distorted competition in the market.
- Demand side response has witnessed strong growth in capacity market post-suspension pre-qualification for next year's auctions that was completed in November of 2019.

Principles for prequalification of DR aggregator

- Existing DSR resources can prequalify for an auction by providing full details and test results.
- Unproven DSR resources do not have to provide any details of the sites involved until shortly before the start of the delivery year. Instead, the participant submits a “business model”, explaining how they intend to procure the necessary capacity. If they clear in the auction they must provide a financial guarantee, which they forfeit if they do not successfully test their capacity by a deadline shortly before the delivery.
- More details can be found in Appendix.

Business model template for Proven DSR

Proven DSR Business Model

Proven DSR CMU ID: [enter CMU ID here]

Name & Location of CMU Component*	Type of DSR effected by the DSR CMU Component*	Summary of the relationship between the DSR Provider and the DSR CMU Component*	Method(s) of achieving load reduction*	Equipment control or installed or to be controlled and installed*	Details of how the DSR Capacity of the DSR CMU has been secured to the DSR Provider*

*all fields are mandatory for every CMU Component

Business model template for Unproven DSR (1/2)

Unproven DSR CMU to which the Business Plan Applies	(insert CMU ID)
---	-----------------

Please provide details of the Unproven DSR CMU proposal including the steps already taken to acquire the DSR Capacity and/or Contractual DSR Control

Please complete the following table for each DSR CMU Component with which the DSR Provider has already established a relationship

Name & Location of CMU Component	Type of DSR effected by the DSR CMU Component	Summary of the relationship between the DSR Provider and the DSR CMU Component	Meter Point Administration Number(s) or details of other meter(s) used to measure provision of DSR (N/A if DSR Test Certificate included for CMU)	Metering Test Certificate or metering configuration (N/A if DSR Test Certificate included for CMU)	Method(s) of achieving load reduction	Equipment control or installed or to be controlled and installed	Details of how the DSR Capacity of the DSR CMU has been secured to the DSR Provider

Business model template for Unproven DSR (2/2)

Please complete the following table as far as information is available for each DSR CMU Component with which the DSR Provider intends to establish a relationship

Name & Location of CMU Component	Type of DSR effected by the DSR CMU Component	Summary of the relationship between the DSR Provider and the DSR CMU Component	Meter Point Administration Number(s) or details of other meter(s) used to measure provision of DSR (N/A if DSR Test Certificate included for CMU)	Metering Test Certificate or metering configuration (N/A if DSR Test Certificate included for CMU)	Method(s) of achieving load reduction	Equipment control or installed or to be controlled and installed	Details of how the DSR Capacity of the DSR CMU has been secured to the DSR Provider

Please provide details of the programme or strategy for procuring any further DSR CMU Components to ensure that the Unproven DSR Capacity is available, including:

- i) Method(s) of achieving load reduction
- ii) Equipment controlled or installed, or to be controlled or installed
- iii) Details of how the DSR Capacity of the DSR CMU has, or will be secured to the DSR Provider
- iv) Any additional information as previously specified as being required by the Delivery Body [in the Auction Guidelines] for an Unproven DSR CMU

Q&A #1

Question:

Who selects the particular source (generator or DSR) in the case of a stress event occurring and how this decision is being made?

Answer:

Currently nobody selects which resources should respond during a stress event.

Instead, the expectation is that every resource should respond to every stress event. In fact, it's even sillier than that: you don't get told whether there is a stress event until the following day. You get a warning that there could be a stress event, four hours in advance, but no confirmation. So the only way to be sure that you meet your obligation would be to start delivering 4 hours after you receive a warning, and carry on delivering until the warning is cancelled. Either that, or you try to guess whether and when there will be an actual stress event.

This approach is an artefact of designing the market while thinking only about conventional generators: the thinking was that in the circumstances in which a stress event might occur, all generators would want to be running anyway, as energy prices would be likely to be above their short-run operating costs. This is not the case for DR, and this adds hugely (and needlessly) to the costs and risks of participation.

Content

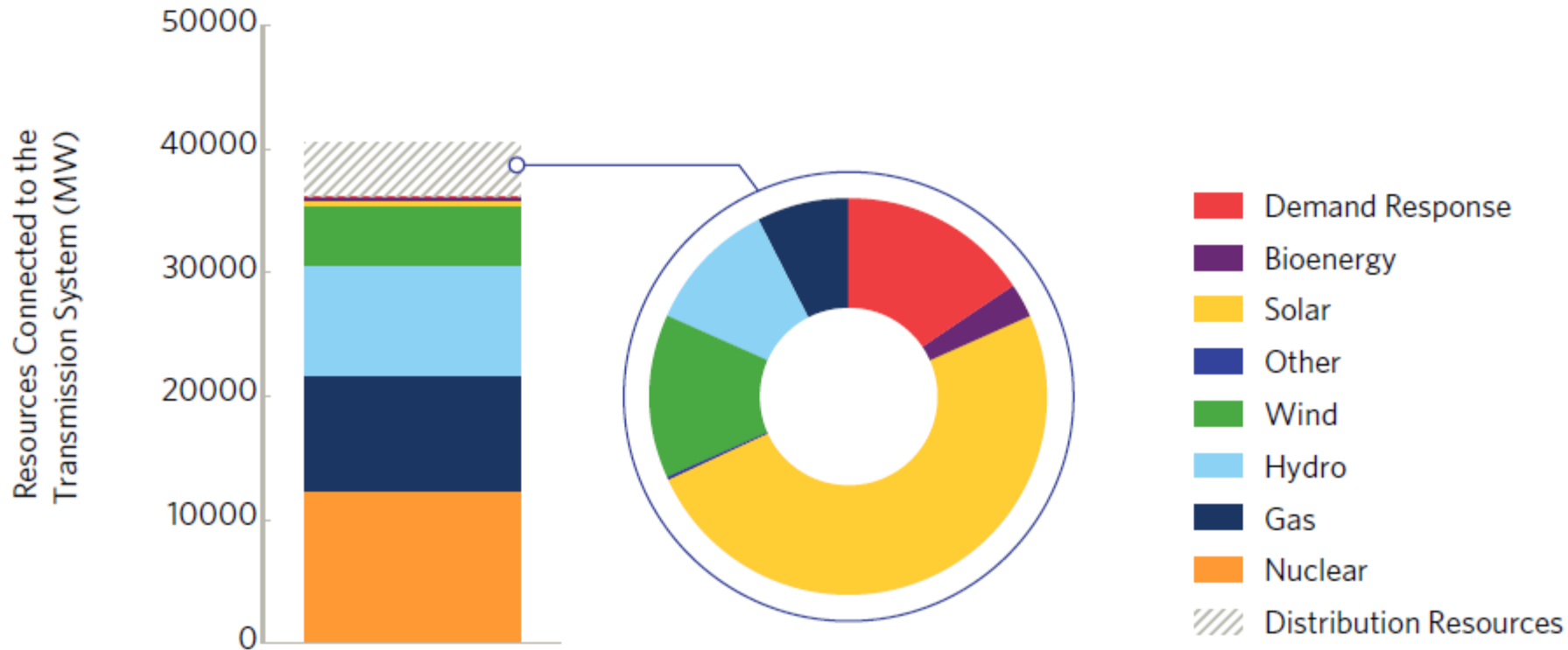
1	USA - PJM
2	UK - National Grid
3	Ontario - IESO
4	Implications for Russia

Ontario - General Characteristics



- Ontario – province in the central part of Canada
- IESO (The Independent Electricity System Operator) – manages the power system in real-time, plans for the province's future energy needs, and enables efficient electricity marketplace to support sector evolution.
- General characteristics of the energy system:
 - Population: 14,5 mln people
 - Installed generation capacity : 37,5 GW at transmission level and 3,4 GW of distributed generation
 - Peak load: 23,240 MW
 - Electricity volume : 137 400 GWh per year
 - Territory: over 1 mln square km

DR role in Ontario's Energy Mix

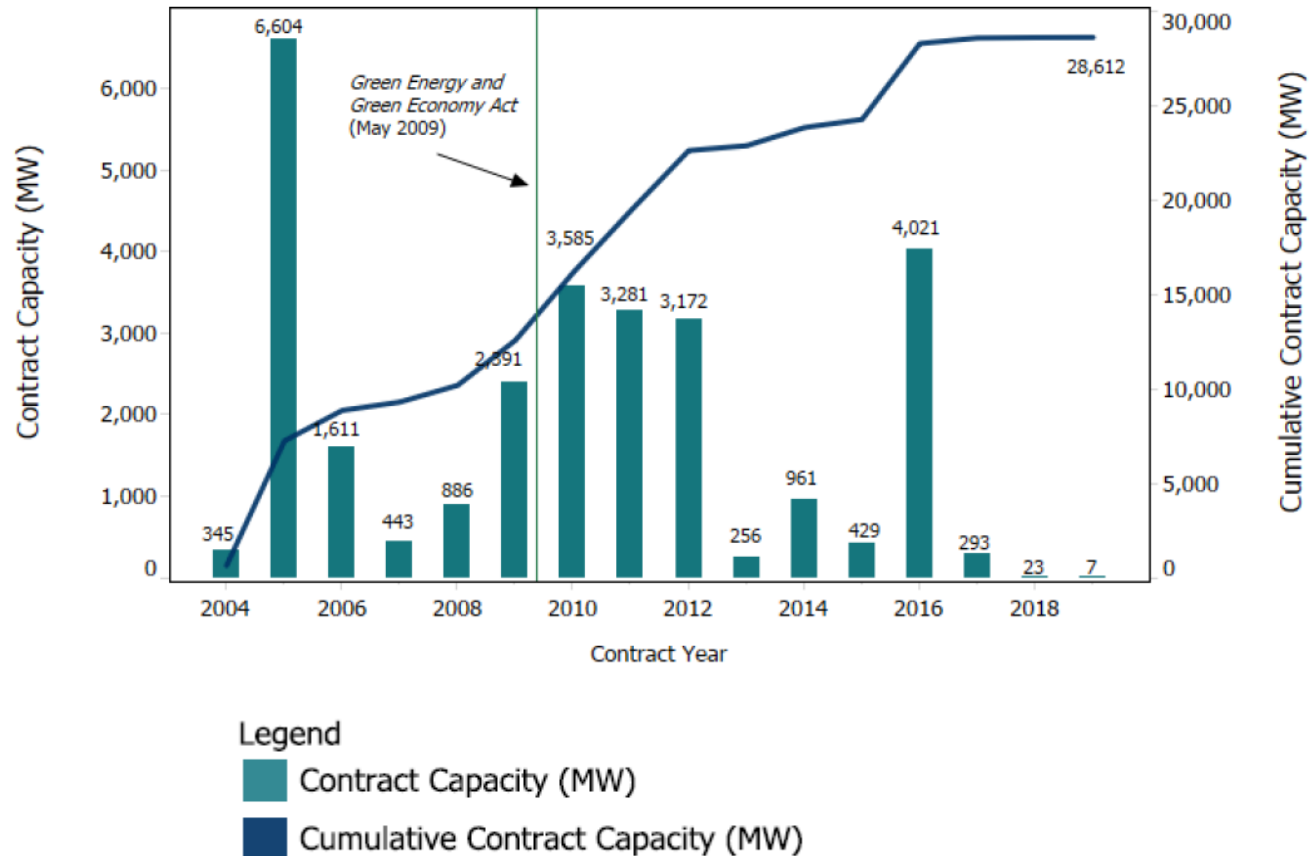


~**4,400 MW**

DERs contracted or installed over the past 10 years represent nearly 10 per cent of Ontario's electricity capacity

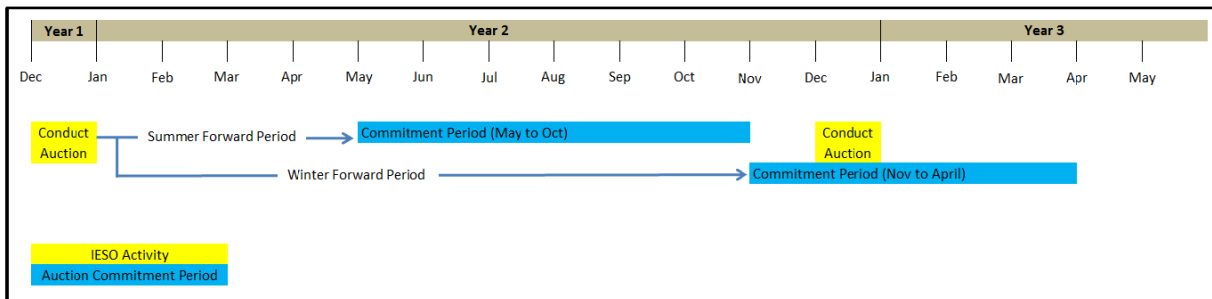
Capacity Procurement Practices in Ontario

Timeline of Contracts Executed



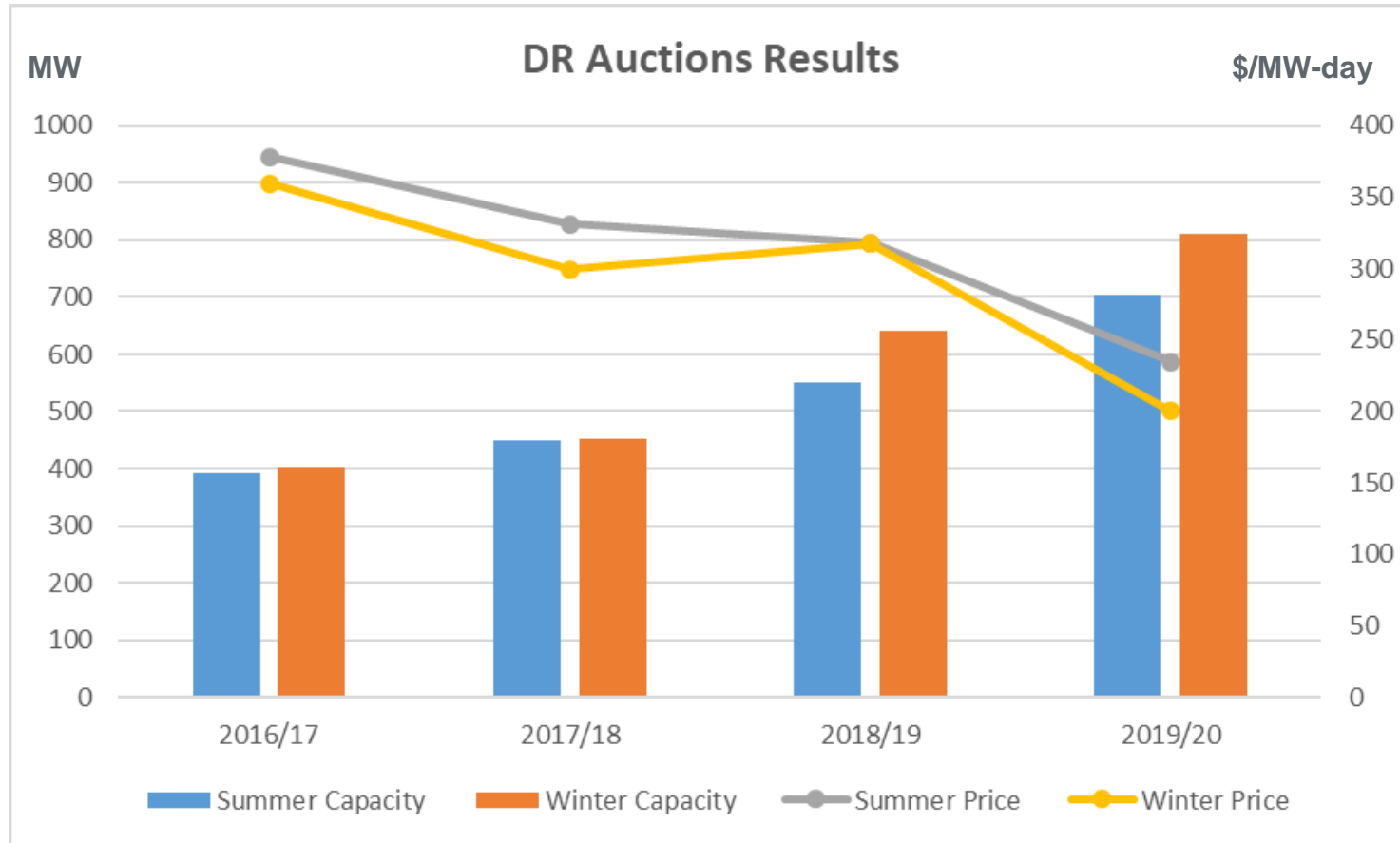
- The Ontario government has been inviting investment in generation technologies and facilities to supply new generation capacity.
- This additional electricity has been procured through fixed term contracts with suppliers for renewable energy, natural gas and nuclear energy, and energy produced from municipal waste.
- The Ministry of Energy determines the procurement levels for each fuel type based on its Long-Term Energy Plan. The IESO administers each contract that has been executed under the specific procurements, programs or initiatives.
- The procurement methodologies used to acquire contracted capacities are standard offer, bi-lateral negotiations or competitive bids.
- Currently IESO is managing 33,757 contracts, which have a combined capacity of 26,762 MW.
- The total amount of contracted capacity in commercial operation was 25,220 MW, while 1,542 MW remained under development.

Demand Response Auctions



- For the past three years, the Independent Electricity System Operator (IESO) has managed two Demand Response Programs: the Capacity-Based Demand Response (CBDR) program and the competitive Demand Response Auction (DRA). CBDR was initially created as a temporary program to ease the transition from the previous demand response program operated by the Ontario Power Authority—which merged with the IESO in 2015—to the DRA.
- The auction provides a transparent and cost-effective way to select the most competitive providers of demand response.
- It takes offers from large companies and aggregators (representing a group of commercial energy consumers) that commit to reducing their energy use in response to an instruction from IESO.
- The DR auction was the IESO's first competitive market for capacity. Since launching in 2015, the auction has succeeded in increasing competition among demand-response providers (including industrial, commercial, and residential), using a variety of technologies, and significantly reducing the costs as a result.

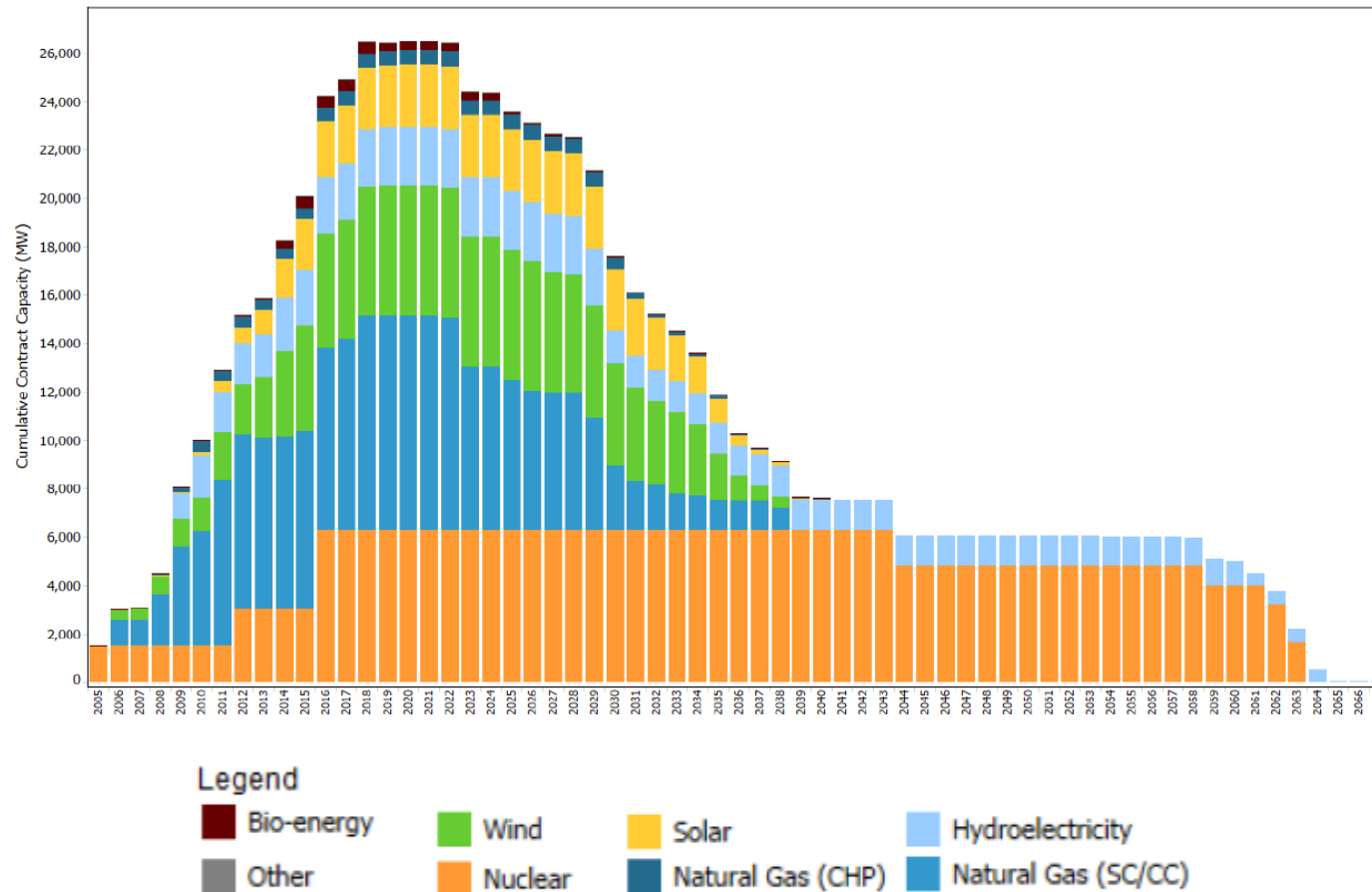
Results of DR Auctions for 2016-2020



- Four auctions have been held since 2015. The next auction will be held in December 2019, for delivery of DR capacity between May 2020 and April 2021.
- In 2018 auction the average clearing price for the summer period decreased by 38% and for the winter period – by 44% compared to the first auction in 2015.
- Number of participants has grown from 6 to 38.

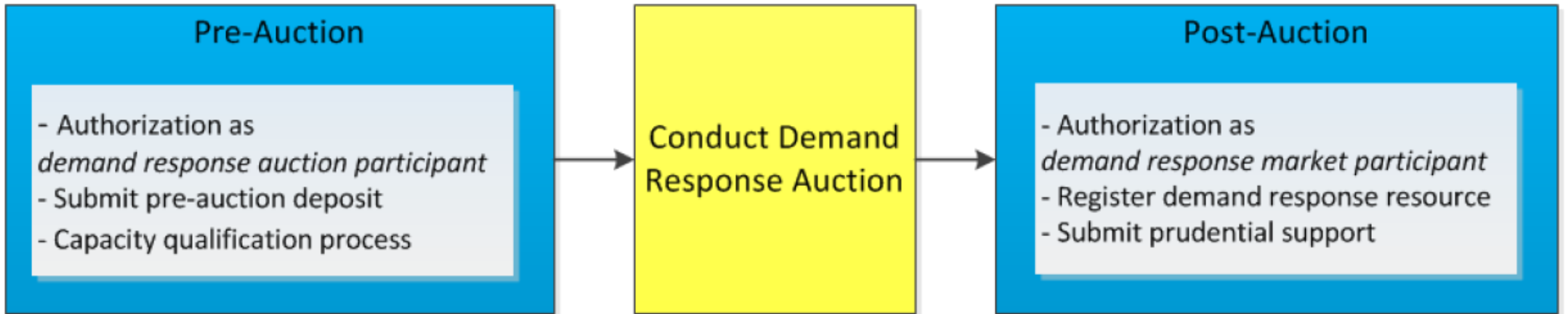
Market Renewal Program

Projected Lifecycle for Contracted Capacity

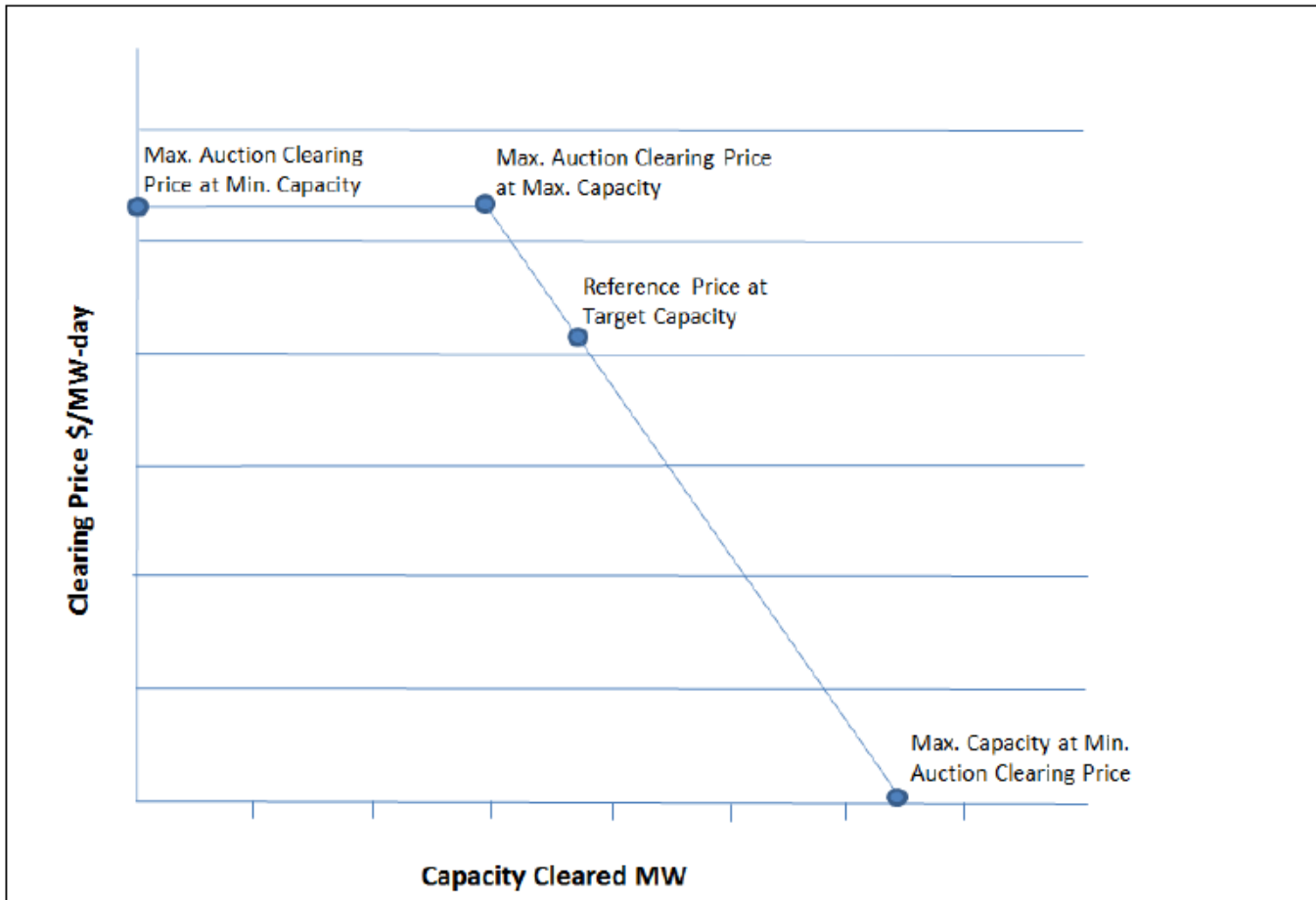


- As existing capacity commitments start to expire, IESO launches a Market Renewal Program.
- One of its elements involves development of a capacity market on the basis of DR auctions.
- Market operator plans to open the auction to new resources, including generators that are no longer on contract with the IESO.
- Gradually this new mechanism will involve new type of resources – like imports and storage.
- At the same time nuclear and large hydro facilities will be procured under a different scheme.

Demand Response Auction Process

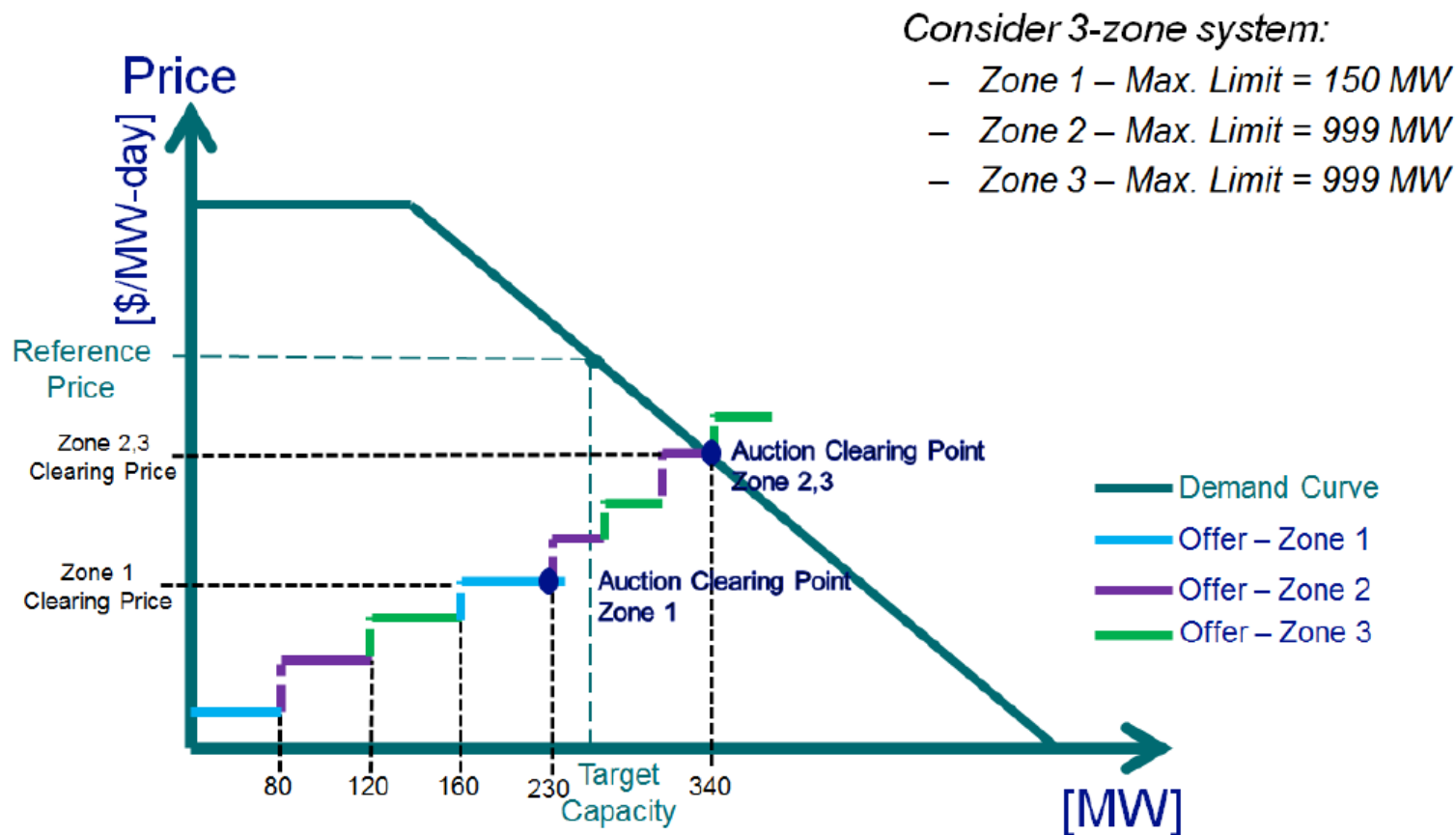


Demand Curve Elements

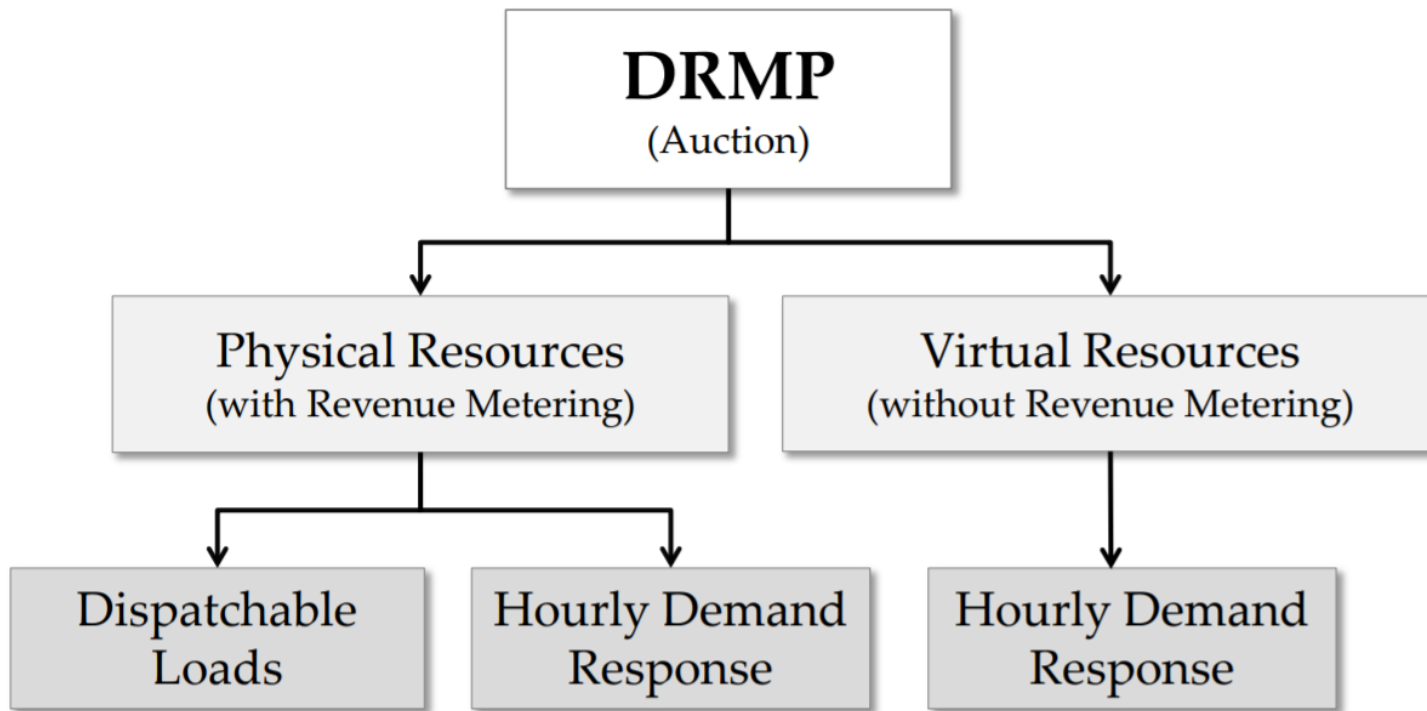


- Given the dynamic nature of the energy market, the IESO will review the demand curve parameters at least once every three years to ensure it is reflective of the current market conditions and system needs
- The target capacity for each commitment period will be determined based on the following factors:
 - the amount of quantity exiting the capacity based demand response program,
 - the target capacity from the previous demand response auction, and
 - any additional needs identified by the IESO.

Auction Selection Process with Zonal Limits



Types of Demand Response Resources



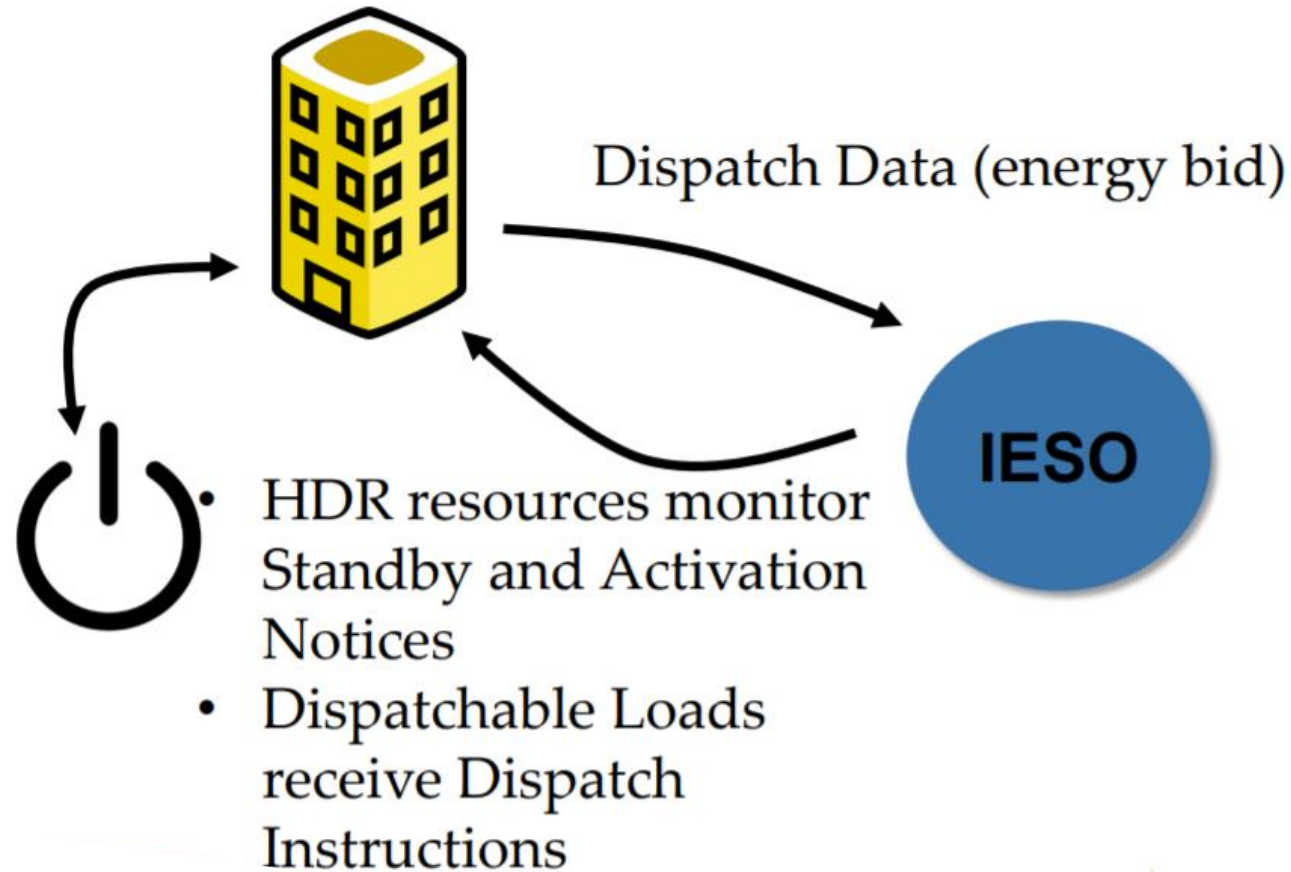
- **Physical demand response resources** are those that are revenue-metered by the IESO (wholesale meters) and fully participate in the energy market
- **Virtual demand response resources** are those with LDC meters (e.g. an aggregator with residential customers as contributors)
- **Dispatchable Load** – resource that can respond to a 5 minute dispatch instruction and whose demand is scheduled based on the price of energy
- **Hourly Demand Response** - load resources that are required to register as IESO market participants but are not subject to dispatch by the IESO and whose demand is not scheduled based on the price of energy

Measurement Data Submissions

Measurement Data Submissions

- If you have a revenue wholesale meter, the IESO will collect measurement data and you will not be required to submit this data
- Aggregators must submit contributor data whose meter type is other than a revenue wholesale meter
- Submitted meter data should be the sum of the total contributors not revenue metered by the IESO
- DR participants with virtual contributors are required to submit monthly five-minute interval measurement data (single one month data file per virtual meter point ID) through new Online IESO – DR Measurement Data Submission
- DR participants must also submit an additional two months of historical measurement data when they have a new contributor change
- You must submit meter data no later than the sixth business day before the end of the following month

Energy Market Participation (1/3)



- DR market participants are expected to meet their capacity obligations by participating in the energy market by:
 - Submitting dispatch data in the day-ahead commitment process and in the real-time market;
 - Submitting outage requests if required; and
 - Demonstrating ability to deliver capacity obligations by responding to the dispatch instructions (including test activations).

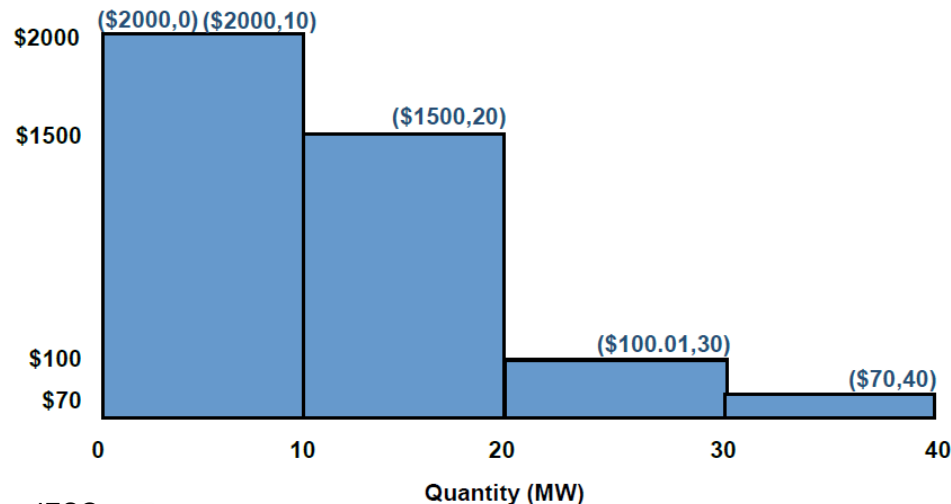
Energy Market Participation (2/3)

Submitting Dispatch Data

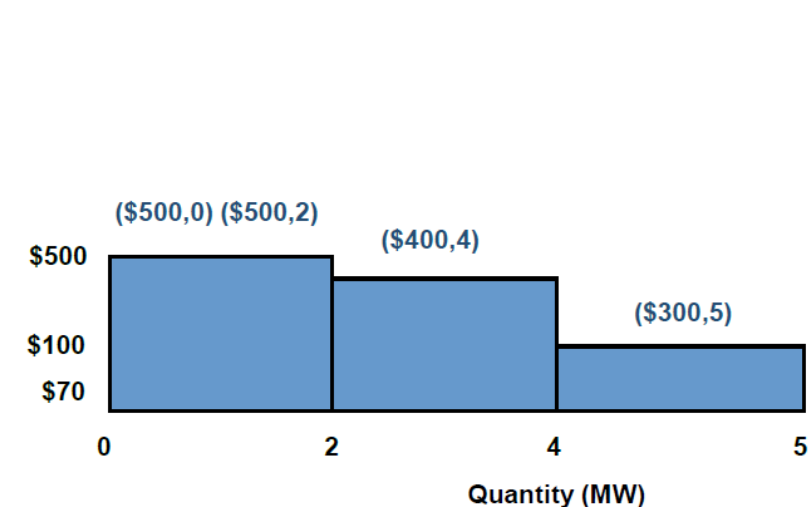
Demand Response Market Participants will submit dispatch data (bids) that reflects their price sensitivity during the availability window of a commitment period:

- Day/hour - 24 hourly groups of information (HDR participants will only bid during the availability hours), the furthest into the future you can bid is one day after the current day
- Price/quantity pairs - you can submit up to 20 price/quantity(P/Q) pairs for energy for a single resource for any given hour. Price your DR capacity between the maximum market clearing price (\$2000) and greater than the Bid Price threshold (\$100).
- Ramp rates - specify up/down rates and the applicable operating range.
- Resource ID

Price/Quantity Pairs – Bids DL



Price/Quantity Pairs – Bids HDR



Energy Market Participation (3/3)

Standby and Activation of DR Resources

- Monitor the Standby Report for a Standby Notice from 15:00 EST day ahead until 07:00 EST on the dispatch day
- If you receive a Standby Notice, move on to monitoring for an Activation. If you do not receive a Standby Notice, remove your bids.
- An Activation Notice will occur ~2.5 hours in advance of an activation.

Sample Demand Response Activation Report

Resource Name		Scheduled MW for Hour																							
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
RESOURCE_2	Energy Bid (MW)													15	15	15	15								
	Energy Schedule (MW)													10	9	8	7								
	DR Curtailment (MW)													5	6	7	8								
RESOURCE_1	Energy Bid (MW)															20	20	20	20						
	Energy Schedule (MW)															10	9	8	7						
	DR Curtailment (MW)															10	11	12	13						

Settlement and Availability Payment

$$\sum_{d=1}^n DRCO_k \times DRACP$$

Where:

- 'd' is a business day in the month
- 'n' is the number of applicable business days in the month
- $DRCO_k$ is the DR Capacity Obligation (MW) on day 'd'
- DRACP is the DR Auction Clearing Price

- Settlement of DR Capacity Obligations begins upon completion of required registration activities
- Participants with DR capacity obligations will receive a monthly availability payment calculated based on the number of business days in a given month, capacity obligation and DR auction clearing price
- For example, if a certain month had 21 business days while auction price was \$378.21 per MW-day, participant with 10 MW capacity obligation will receive availability payment:

$$21 \times 10 \times 378.21 = \textbf{\$79 424.10}$$

- Four types of non-performance charges may apply (availability charge, administration charge, dispatch charge, and capacity charge)

Test Activations

Test Activations

Two test activations may be scheduled during each obligation period for all resources with a capacity obligation. During the test, participants is expected to demonstrate a reduction in energy withdrawal or increase in energy production equal to the offered capacity of his resource.

Failure to perform a successful test activation may result in one or more of the following:

- Non-performance charges;
- A subsequent test activation; and/or
- A compliance investigation.

Q&A #1

Question:

How is the boundary of the individual consumer being defined?

Answer:

Consumers that make up each aggregation must be registered by individual distribution company account number.

Question:

Which source of data is used to estimate consumer's actual consumption (load serving entity, distribution company, curtailment service provider, etc.)?

Answer:

Meter data is collected from the local distribution company.

Question:

What are requirements and the process for qualifying as DR aggregator?

Answer:

DR aggregators must register with the IESO in order to participate in the capacity auction (requirements include financial information, proof of prudential support, application fees).

Q&A #2 (1/2)

Question:

Is an electronic register of consumers of the retail market formed that contains information about the boundaries of the consumer site and about electricity metering devices used to measure the consumption of such an object? If so, who is the holder of such a registry?

Answer:

No, to my knowledge there is no central registry of all retail customers that the SO can use to verify participant data. However, the aggregator must submit the following information when registering customers in the program (Section 6.2.1 of Manual 12).

This data is not verified individually before the customer can participate, because no such central registry exists. However, aggregators are subject to random audits on measurement data and site information. Aggregators also have to submit a one line diagram when there are multiple distribution meters at the site, OR if the customer uses behind-the-meter generation.

Installation:

- Address
- Point of delivery (Premise ID)
- Multiplier used for billing

Q&A #2 (2/2)

Answer (cont.):

Meter & instrument transformer:

- Inspection numbers
- Make
- Serial number
- Type
- Volts
- Amps
- Multiplier
- Seal year
- Measurement Canada Notice of Approval

Q&A #3

Question:

How do DR aggregator and retail participants get compensated for demand curtailment?

How is the volume of curtailment being estimated and controlled?

Answer:

DR aggregators are paid the market's auction clearing price. IESO has a uniform price model (same as our previous examples in UK NGrid and PJM), where all market participants receive the same price.

DR customers are either paid a revenue split of the market clearing price, or are compensated at a fixed rate determined in the contract between the aggregator and customer.

The IESO customer baseline is based on the aggregated resource's highest 15 demand days over the past 20 business days, and baseline is then determined for each DR customer by averaging individual demand in the dispatch hours over the 15 days.

Q&A #4

Question:

How does Enel X recruit retail DR participants and which requirements do they have to fulfil in order to qualify?

Answer:

Same as our other programs - here is a summary:

- Aggregation allows DR providers to assemble a portfolio of diverse customers of varying sizes and consumption patterns
- Because of this, while there are some qualification criteria dictated by the program operator, aggregators can do most of the qualification process themselves
- Some program qualification criteria include offer size (100 kW is usual threshold for individual customer), and metering capabilities
- Enel X process to assess potential customers/DR participants: establish load profile based on billing/interval data, and initial operational plan for load response (which equipment to turn off, operational schedule of customer). This creates the business case.
- Good customers have production/operating flexibility, proper staffing for reliable response, and a load pattern that aligns with the program's likely dispatch days/hours

Q&A #5

Question:

Since DR resources are being compensated based on a uniform price model (all market participants receiving the same price) – what is their incentive to submit flexible pricing bids into the energy market?

Even more so – why would they not submit a flat bid at the highest price to avoid being dispatched (since they still would get their payment anyway)?

Do you have information on the history of events when DR resources were actually activated by IESO during the past four years?

Answer:

It's true that most resources in the DR Auction bid into the energy market at close to the market cap (\$2000/MWh). There is the nuance that DR must bid below the market cap, so most resources bid at \$1999/MWh. The principle that demand response is best used for rare system contingency events because of low availability costs but high variable cost holds true in the IESO DR program design. We also saw this in PJM, which dispatched ELRP resources in 2019 for the first time in 5 years.

So, while DR may only be economic in a few hours during extreme system stress, it's still a cheaper alternative to the equivalent peaking generator that would also only operate for those relatively few hours. In IESO DRA, energy bids fulfill availability requirements (equal to resource capacity) and are required to receive availability payments. Aggregator failure to bid into the energy market results in an “availability charge” equal to the availability payment multiplied by a penalty factor.

There were no DR dispatches due to system stress in 2016-2019.

Content

1	USA - PJM
2	UK - National Grid
3	Ontario - IESO
4	Implications for Russia

Study's implications for Russia (1/4)

1. DR retail resources can become an important element of the Russian energy system both from the volume point of view (3-7% from annual peak load, which will constitute from 5 to 11 GW of capacity for UES) and the role they can play in the country's energy balance (for example, they do not produce any harmful or greenhouse gases).
2. In the target model, retail DR program shall be integrated into existing wholesale market of electricity and capacity.
3. Most appropriate element of the wholesale market, based on the international practices, is capacity market – main principle can be equal treatment of supply (generation) and demand (consumers).
4. As retail DR programs gain experience, it will be possible to gradually expand the area of application of demand-side resources (for example, not only use them for supplying sufficient capacity volumes to cover all possible peak demand, but also involve consumers in peak shaving activities when they substitute most expensive generation) as well as continue to integrate DR programs into other segments of the wholesale market (electricity market, ancillary services market).

Study's implications for Russia (2/4)

5. Pilot stage of the program is very important in order to test methodology and promote the program among consumers / aggregators – as their number grows, participation requirements can be gradually enhanced in order to strengthen the quality of participating resources and open new possibility to their usage in the energy system. Pilot terms should be in line with the target model – otherwise there is a risk that pilot outcomes will not be applicable in the future.
6. It is important to follow flexible and differentiated approach to various types of demand-side resources taking into account differences in ability and willingness of consumers to curtail their demand under different frequency and volume requirements (most of consumers consider participation in DR programs as minor supplementary income source and therefore they are not ready to modify regular consumption patterns on a large scale and very often).
7. Demand aggregators play important role in implementation of retail DR programs in addition to local electric distribution companies and load serving entities.
8. Aggregators can carry mid-term obligations to reduce certain volume of load that they successfully fulfil afterwards even without having signed contractual arrangements with specific final consumers for significant share of their portfolio, since some of these consumers might not be known 4 years prior to delivery period (and even 1 year in advance).

Study's implications for Russia (3/4)

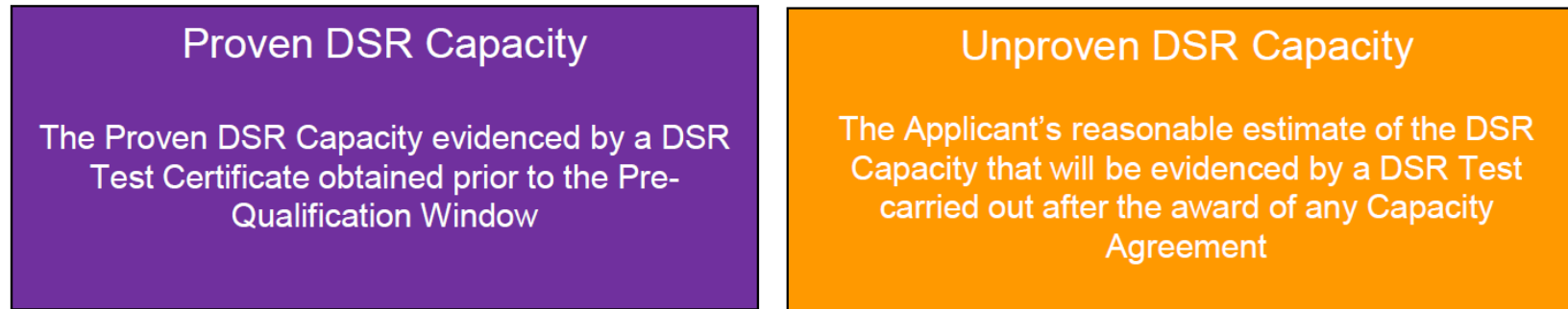
9. It would be extremely onerous and wasteful to expect aggregators to expend huge amounts of effort recruiting customers before they know whether they have cleared in the auction. Requiring such speculative investment would deter participation. In addition, even if an aggregator was willing to do this, they would find it difficult to recruit customers when they do not know the clearing price, so they cannot say how much they will be able to pay them.
10. Aggregation of multiple final consumers allows creation of diversified portfolio of resources with lower risk profile in terms of ability to fulfill demand curtailment obligations and as result – higher service level for the System Operator.
11. Participation of professional demand aggregators helps to share unified approaches and best practices in terms of load curtailment potential assessment for a particular final consumer, as well as implementation of specific actions allowing to reach this potential with minimum costs.
12. Tools and methods for control of actual curtailment size as well as program participation processes are well established and can be adopted to Russian specifics.

Study's implications for Russia (4/4)

13. In the auction process design, it is worthwhile to combine mid-term horizon (3-4 years prior to delivery date) with possibility of short-term correction (1 year prior before the start) while contract duration for the pilot phase shall be extended to 1 year.
14. Specific program conditions (period, duration and volume of curtailment, etc.) can smoothly change along gaining of experience, expanding pool of participants and evolving the needs of the energy system.
15. For continuing development of the demand response pilot the following point will be important to consider:
 - Within international practices DR resources more often play a role of “insurance” rather than “active driver” despite the fact that participating consumers are being paid by the System Operator – too many dispatches will negatively influence the market and willingness of consumers to participate in these programs.
 - Penalties are effective to improve the program reliability.
 - Auction rules need to be clear and well known in advance.

Appendix – Prequalification of DR aggregator (UK case)

Prequalification of DR aggregator case (1/2)



- Company FF is an aggregator with a portfolio of Demand Side Response resources and back-up generation, having contractual control over the DSR resource. These resources are of varying size, between 0.1MW and 49MW. The generation runs periodically rather than as baseload, and does not have a connection agreement to export onto the Distribution Network. FF intends to expand the portfolio if successful in the Capacity Auction, and so wishes to prequalify some existing and new DSR resources.
- The aggregator may determine the most appropriate configuration of CMUs and CMU components across its portfolio, subject to the following rules:
 - All components within a CMU must be of the same type (e.g. DSR or existing generation)
 - Resources should be aggregated to meet the CMU minimum size threshold of 2MW and should not exceed 50MW in size
- In this case, the generation units do not export directly to the Distribution System, and can therefore be treated as part of a DSR CMU. The Rules and Regulations also allow DSR CMUs to incorporate 'permitted on-site generating units', which are primarily used for on-site supply and only export electricity after meeting on-site requirements.

Prequalification of DR aggregator case (2/2)

- Prequalification Applications for DSR resources can be made for either Proven or Unproven capacity. To prequalify as a Proven DSR CMU, a DSR test must be completed prior to the Prequalification Window. Alternatively, DSR resources may qualify as Unproven and commit to complete a DSR Test at least one month before the Delivery Year. Credit cover for Unproven DSR resources will need to be posted with the Settlement Body following Prequalification. In order to minimise its credit cover requirements, aggregator FF submits a Proven CMU Application for its existing resources (F1) and a separate Unproven CMU Application for its new DSR resources (F2), having already completed DSR Tests for the existing resources.
- The Metering Assessment for DSR CMUs provides for a choice of metering pathways. The information required for each metering pathway option is set out in the Auction Guidelines. Proven CMUs will complete the Metering Assessment during Prequalification, while Unproven CMUs must confirm that a Metering Assessment will be completed prior to the Delivery Year.
- The Additional Information required to support the Proven DSR Prequalification application for F1 is as follows:
 - DSR Test Certificate
 - Details of all such generating units and their electrical connections to the site where DSR Capacity is being provided
 - Business model description (see detailed template on a separate slide)
- The Additional Information required for the Unproven DSR unit, F2, is as follows:
 - Confirmation that the a DSR Test will be completed prior to the start of the relevant Delivery Year
 - Confirmation a Metering Assessment, and if necessary a Metering Test, will be completed prior to the start of the relevant Delivery Year
 - Business plan (see detailed template on a separate slide)