Demand side participation forecast and methodology

August 2019

Estimating existing and future demand side participation in the National Electricity Market

Important notice

PURPOSE

AEMO publishes this document to describe the demand side participation forecast methodology and the extent to which, in general terms, demand side participation information received under rule 3.7D has informed AEMO's development or use of load forecasts for the purposes of the exercise of its functions under the National Electricity Rules.

This publication has been prepared by AEMO using information available at 1 July 2019. Information made available after this date may have been included in this publication where practical.

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VERSION CONTROL

Version	Release date	Changes
1.0	22/8/2019	Initial release

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1. Introduction

To maintain a secure and reliable system, a range of interdependent technical and operational needs must be met at all times. This culminates in the continuous matching of supply with demand and constant provision of essential voltage and frequency management services, ensuring sufficient reserves so the power system is robust enough to cope with unexpected events and stay within the power system operational design limits.

The National Electricity Market (NEM), like power systems worldwide, is being transformed from a system dominated by large thermal power stations, to a system including a multitude of power generation resources and technologies of various sizes. The transformation is evident in trends towards Increasing diversity of supply resources, continuing decentralisation of generation assets, and increasingly active consumers and market participants.

Demand side participation (DSP) can help to balance supply with demand. It refers to activities performed by consumers to reduce demand due to various triggers and has been observed in the NEM for many years, although at relatively minor contributions.

In light of the trends in the transformation of the power system, DSP as a resource is expected to grow over time, making forecasting DSP an increasingly important influence on the supply levels and reserves necessary to maintain a reliable and secure power system.

Drivers of DSP include, for example, the Australian Energy Market Commission (AEMC) Rule change proposal intended to promote additional DSP in the wholesale market[1] (currently at draft determination phase). Another driver is technological development, with the potential for DSP increasing due to a combination of growth in:

- The number of smart meter installations.
- Tariff offerings that promote change to consumption behaviour at specific times or during various events.
- Uptake of technologies that provide flexibility, either through being controllable (such as grid-smart air-conditioners based on Australian Standard 4755.2), or the nature of the demand being flexible (charging/discharging of home battery installations and charging of electric vehicles).

1.1 What is DSP?

Contracted DSP is defined in clause 3.7D(a) of the National Electricity Rules (NER) as a contractual arrangement between a Registered Participant and a person, in which they agree to the curtailment of non-scheduled load or the provision of unscheduled generation in specified circumstances.

In addition to contracted DSP, through clause 3.7D(e)(1)(ii), DSP includes curtailment of non-scheduled load or provision of non-scheduled generation in response to the demand for, or price of, electricity.

For practical application in electricity supply adequacy and market modelling studies, DSP may include:

- Market-driven responses:
  - This category includes residential, commercial, and industrial responses that are typically triggered in respect to the price of electricity.
  - Examples include industrial facilities that are exposed to the wholesale price and elect to reduce electric load at times of high prices, consumers that agree to let their battery be controlled by a third party or are incentivised to switch off air-conditioners, and small non-scheduled generators that have the ability to produce electricity at these times, offsetting local consumption.

[1] See https://www.aemc.gov.au/rule-changes/wholesale-demand-response-mechanism.

- Reliability event responses:
  - This category includes responses that are called on when power system reliability requires support. They are most common under Lack of Reserve (LOR) conditions, although they often also coincide with high wholesale prices. These responses can be contracted.
  - Examples include load reductions in response to directions from AEMO's Reliability and Emergency Reserve Trader (RERT) function[2]. Additionally, network event programs that may be aimed at distribution network demand management are included in the reliability event group; on a set maximum number of days per year, networks may call on agreements to reduce demand or incentivise reductions through temporary increases in electricity costs.

1.2 DSP considered in AEMO's studies

AEMO's estimation and forecasts of DSP aim to account for market-driven and reliability event responses by electricity consumers or generators, where the responses are not already accounted for in its demand forecasts or supply models. AEMO analyses the information submitted through the Demand Side Participation Information Portal (DSP IP)[3] and incorporates other lists that AEMO maintains (including large industrial facilities and RERT program participants).

AEMO excludes customer responses that have been observed to be consistent and routine, and not in response to a price or demand trigger. These consistent and routine demand activities are instead incorporated in the regional demand forecast, and include daily load control (residential water heating, for example) and businesses where demand fluctuations follow a consistent pattern from day to day, for example, in response to time-of-use tariffs.

Some embedded or small generator responses are excluded from the DSP estimates, because the contribution of these generators to meeting demand is already included in the forecasts of maximum and minimum demand. These generators are part of the Other Non-Scheduled Generators (ONSG) group modelled as part of the demand forecast. AEMO's list of ONSG generally includes separately metered generators. In circumstances where generation cannot be separated from a facility's metered load, it is considered 'behind the meter', and the facility is usually retained in a list for DSP calculations.

RERT responses are excluded from DSP. This is because these non-market responses are procured by AEMO specifically to address potential reliability gaps. AEMO's reliability forecasts (including DSP effects) need to consider supply and demand without these responses, so any reliability gaps can be detected.

1.3 National Electricity Rules requirements

Under NER 3.7D, sub clauses (b), (c) and (d):

- Registered Participants must provide demand side participation information to AEMO in accordance with the demand side participation information guidelines[4].
- AEMO must take into account the demand side participation information it receives under rule 3.7D when developing or using load forecasts for the purposes of the exercise of its functions under the NER.
- AEMO also must publish details, no less than annually, on the extent to which, in general terms, demand side participation information received under rule 3.7D has informed AEMO's development or use of load forecasts for the purposes of the exercise of its functions under the NER.

[2] The Reliability and Emergency Reserve Trader is a function conferred on AEMO to maintain power system reliability and system security using reserve contracts.

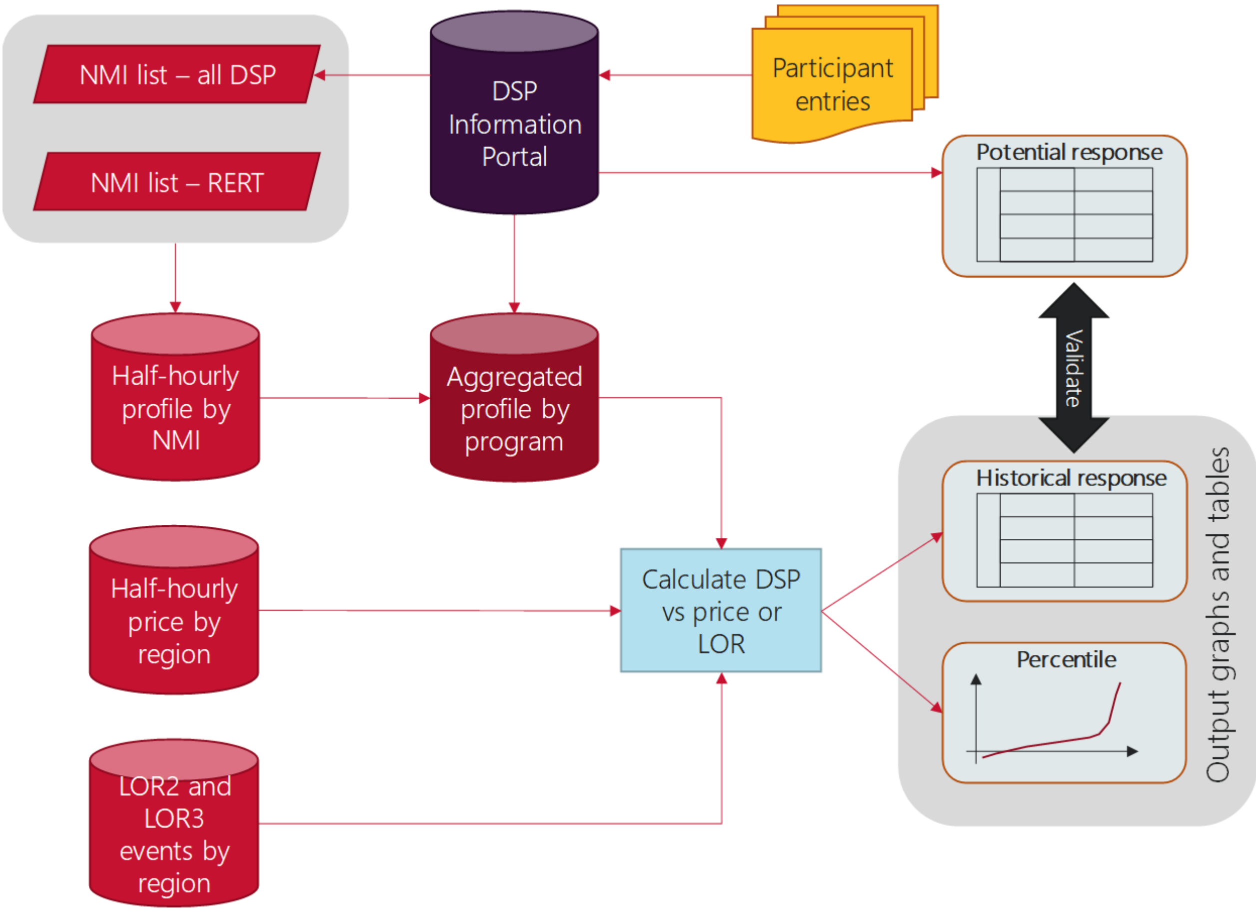
[3] Further information on the DSP IP is at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Demand-Side-Participation-Information-Guidelines

[4] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Demand-Side-Participation-Information-Guidelines

2. Estimating the current level of DSP

Chapter 2 outlines the approach AEMO has used to estimate the current level of DSP in the 2019 DSP forecast. Figure 1 summarises the flow of information that begins with Participant Entries to the DSP IP and ends with the estimation of historical market driven or reliability event responses. The different steps of the process are explained in the following sections.

Figure 1 Overview of DSP forecast process



2.1 Information on DSP programs

Data sources

AEMO collects information from market participants through the DSP IP. Key information submitted to the DSP IP includes national meter identifiers (NMIs) for each customer that meets the criteria of the DSP information guidelines, demand response program information, and potential customer response amounts (in megawatts).

AEMO then:

- Cross-checks the customer NMIs against internally managed lists of large industrial customers, to ensure no large consumers are missed.
- Identifies participants in RERT arrangements.
- Identifies generators referred to as ONSG.

Program groups

To improve the robustness of the DSP calculation process, the NMIs are grouped into program groups.

Some groups are excluded from the AEMO estimation of DSP to avoid double-counting responses that are already included in demand forecasts or supply models. Nevertheless, excluded groups are still considered by AEMO through other processes when assessing the magnitude of total DSP and analysing how consumer behaviour changes with market-driven incentives in the NEM.

The following program groups were used in 2019:

- RERT providers – these customers are excluded from the DSP calculation, because their historical responses are scheduled in agreement with AEMO.
- ONSG – these providers are excluded, because their impact on operational demand is already included in the operational demand forecast.
- Individual industrial loads – many large industrial loads are analysed individually for any response under event trigger conditions. AEMO cross-checks the customer NMIs so no large consumers are missed.
- Customers on network event programs – this includes customers on AusNet Services' critical peak demand tariff and Energy Queensland's controlled air-conditioner program.
- Customers involved in programs relating to connections with network-controlled load:
  - This includes customers on controlled load tariffs for hot water or pool pumps which operate regularly. The effects of these tariffs are already embedded in the demand history, and consequently they are also embedded in the demand forecast – these programs were excluded to avoid double-counting.
  - Selected programs under this category were separated out to capture customers on summer-specific programs and explicit demand management programs. These programs were included to detect response potential under high demand and extreme weather periods.
- Customers with energy storage – these customers were excluded to avoid double-counting. AEMO acknowledges their potential to respond to incentives, however, battery operation is considered explicitly in the demand forecasts and supply modelling.
- Customers on retail time-of-use tariffs – these consumers were excluded to avoid double-counting. Because these tariffs operate regularly, the effects are already embedded in the demand history and consequently, they are also embedded in the demand forecast.
- Other customers included on other programs – this includes market-exposed connections, customers on demand reduction contracts, and individual customers on programs that could incentivise DSP.

Each program group listed above may include one or more NMIs. However, in some cases a particular NMI may be present in several individual programs (and across different program groups). For example, a connection with a residential air-conditioner may be part of a program that may reduce its output during extreme demand days but, at the same address, a hot water heater (and potentially pool pump) may exist, sharing the same NMI. The connection, therefore, could also be on a network-controlled load program if the water heater is controlled (typically switched off and back on every day). In 2019, NMIs appearing in multiple program groups were excluded if found to be in the RERT or ONSG groups but retained otherwise if in a group relevant for DSP calculations.

2.2 Historical time series data

Meter reads (energy consumed at each market interval) are extracted and aggregated by program groups and NEM region, creating program-level time series of actual demand. The length of the time series used in 2019 was three years, designed to be short enough to capture recent customer behaviour, yet long enough to capture a useful number of DSP events.

Time series of wholesale price and periods where LOR events have occurred are also collated. These are used to identify DSP trigger events.

2.2.1 Response by event

Responses are estimated by subtracting baseline demand (Section 2.2.2) from actual demand, for any period where event trigger conditions are met:

- **Price triggers** – to cover a reasonable range of different DSP initiatives, AEMO estimates DSP at the following wholesale electricity price bands:
  - 300 to 500 $ per megawatt hour (MWh).
  - 500 to 1,000 $/MWh.
  - 1,000 to 2,500 $/MWh.
  - 2,500 to 5,000 $/MWh.
  - 5,000 to 7,500 $/MWh.
  - 7,500 $/MWh to the market price cap (MPC).
- **Reliability triggers** – the responses are estimated for periods with:
  - Actual LOR 2 and LOR 3 events[5].

2.2.2 Calculate the baseline

For each event, a baseline is required to estimate the DSP response for the duration of the period the trigger is met. A baseline is an estimate of what a consumer's demand would have been if a DSP response had not occurred.

The subtraction of actual observed demand from the baseline results in the estimate of DSP at a given market interval, for a given program group.

AEMO's approach to calculating baselines from program-level time series is to fit one of two models to each event period and program group[6]:

- A quadratic polynomial, using market period as the explanatory variable, is applied to groups where demand changes smoothly during the day, such as residential demand or consumer demand in aggregate.
- A constant model (flat demand) is applied when model verification suggests that this approach would fit demand better than the polynomial. This is typically useful for industrial facilities which usually consume a steady rate of energy[7].

For each event day, the half-hourly demand used to fit the model excludes the half-hours of the event period.

An illustrative example of an estimated baseline using the polynomial model approach, relative to actual demand, is presented in Figure 2.

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[5] See NER Clause 4.8.4 for definition.

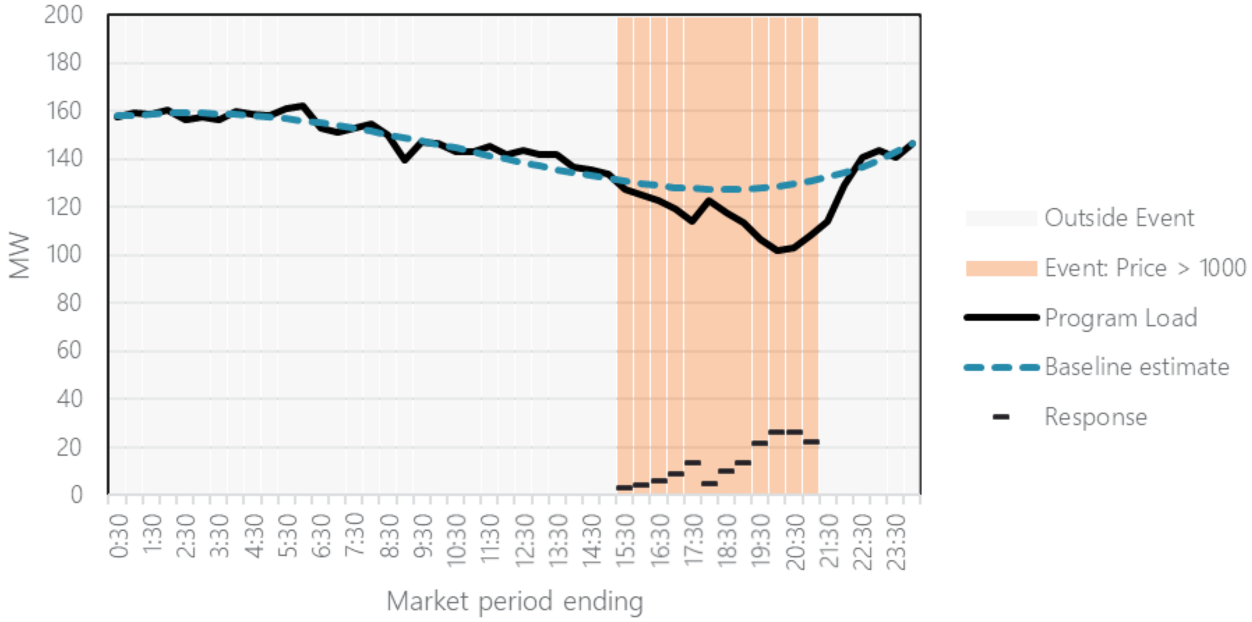
[6] AEMO's adopted approach for estimating baselines was informed by findings reported in Jazaeri, J., Alpcan, T., Gordon, R.L., Brandão, M.F., Hoban, T., and Seeling, C. (2016), "Baseline methodologies for small scale residential demand response". 2016 IEEE Innovative Smart Grid Technologies - Asia (ISGT-Asia), 747-752.

[7] In 2019, AEMO applied the polynomial model to all program groups, because it found that flat patterns were also captured by this approach.

The figure also indicates the ‘event period’, which is the time range where a DSP trigger is determined to have occurred (outlined in Section 2.2.1).

Predictions made using the model provide the baseline for the event period. In situations where an event lasted longer than 43 periods, estimation of the baseline was not possible, as fewer than five ‘actuals’ were available.

Figure 2 Example of baseline estimation and calculated response

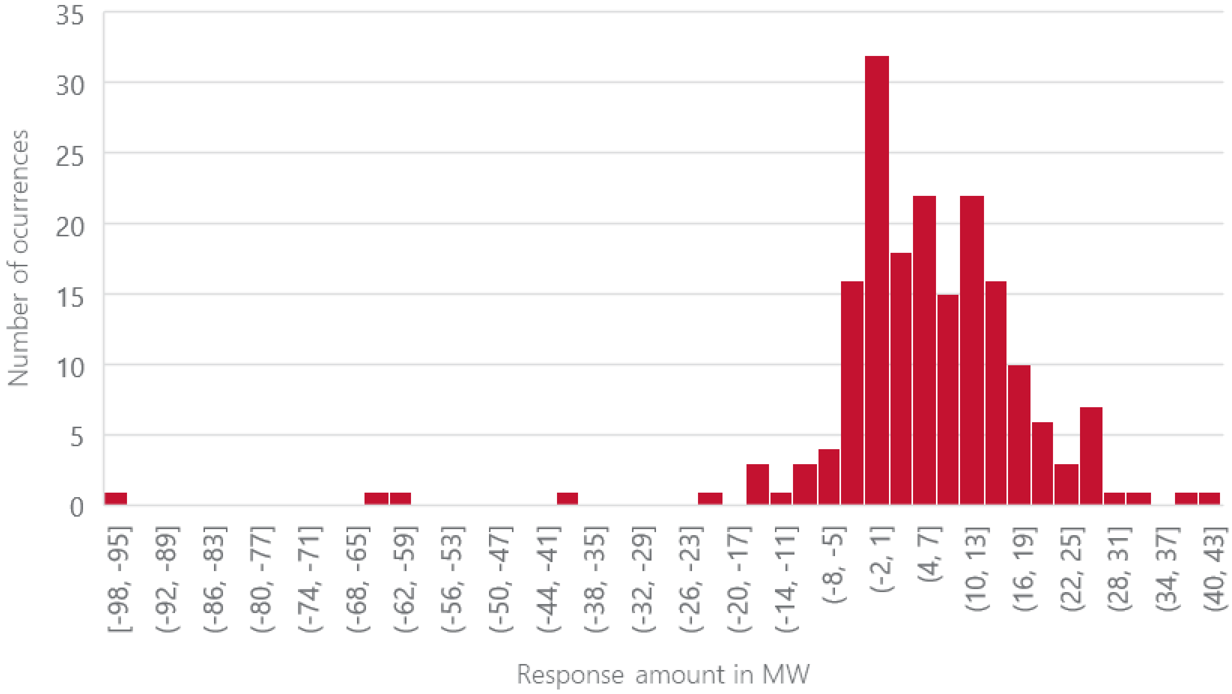


2.2.3 Response probability curve

For each trigger category, historical DSP responses of all the program groups are collated. Collated responses of each program group are summed at each market interval. The responses form the distribution of observed DSP outcomes for each NEM region, program group, and trigger category.

When charted as a histogram, the outcomes can be presented as shown in Figure 3. Alternatively, for multiple trigger levels, the data can be presented as a probability distribution curves as per Figure 4.

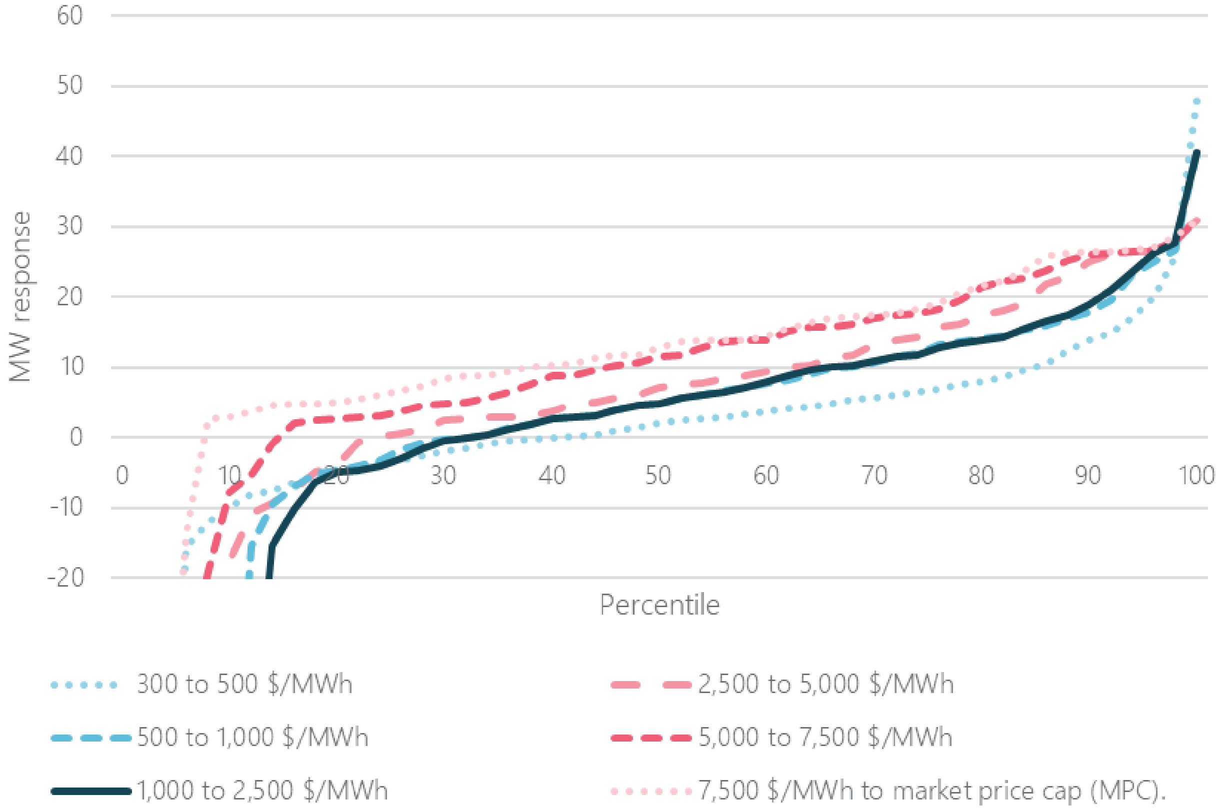
Figure 3 Example DSP response distribution as a histogram



An example of probability distribution curves derived for each price band is presented in Figure 4.

The data is truncated to cover the main percentile of interest – the 50th percentile. AEMO targets the 50th percentile because it represents the midpoint level of response seen in recent history and can be adopted as the most likely estimate of DSP for the future. At the extreme ends of the percentile range, response estimates vary widely, due to atypical behaviour of the load and baseline calculation approach.

Figure 4 Response probability distribution at price bands



2.3 DSP at reliability events

The frequency of LOR 2 and LOR 3 events is very low, meaning that the calculated response probability curve for these events is relatively imprecise. Given the sparseness of the historical events, AEMO uses the 50th percentile response at >$7,500/MWh as an approximation of the likely DSP response at time of capacity shortage.

In addition to the response at prices exceeding $7,500/MWh, AEMO adds the estimated response from network event programs. These can only be called on a limited number of times a year, generally where forecast demand is very high, and reflect loads that would not respond to price by themselves.

AEMO has obtained estimates of the likely response from organisations running these programs and is developing a methodology to validate this response, based on NMI data obtained for customers currently enrolled.

2.4 Application to AEMO's reliability studies

The current estimated level of DSP is used in the following AEMO reliability studies for the duration of each assessment period to ensure that supply adequacy includes only existing and already committed sources of supply (including DSP) to meet peak demand (apart from any exceptions noted below):

- 2019 Electricity Statement of Opportunities for the NEM (ESOO).
- 2019 Energy Adequacy Assessment Projection (EAAP).
- Medium-Term Projected Assessment of System Adequacy (MT PASA).

AEMO's Integrated System Plan (ISP) also uses DSP forecasts. The ISP DSP forecasts vary from the estimated DSP for reliability studies presented below, with the ISP forecasts including assumed year-on-year growth (explained in Section 3).

Estimated DSP for reliability studies

The estimated current level of DSP is set out in Table 1 for summer and Table 2 for winter.

The tables show cumulative response at various price levels. For example, for summer 2019-20 in New South Wales, 42 MW of demand reduction is estimated for prices exceeding $300/MWh, while the response is estimated to be 80 MW for prices exceeding $1,000/MWh. These estimates are not cumulative – that is, the 80 MW estimated to be available at prices exceeding $1,000/MWh includes the 42 MW DSP estimated to be available at prices exceeding $300/MWh.

The reliability response refers to situations where an actual LOR 2 or LOR3 notice is issued (NER Clause 4.8.4). For New South Wales in summer 2019-20, for example, 93 MW is the estimated reduction in demand.

The listed drop in DSP capacity for Victoria from summer 2020-21 and beyond is due to a major load currently in operation (and assumed to be curtailable under LOR 2 and 3 conditions) that is projected not to operate from 1 July 2020 onwards.

Table 1 Summer DSP estimate for reliability studies (MW)

Trigger	Summer	NSW	QLD	SA	TAS	VIC
> $300/MWh	2019-20	42	6	4	0	14
> $500/MWh	2019-20	78	11	11	1	46
> $1000/MWh	2019-20	80	12	12	30	50
> $2500/MWh	2019-20	86	25	19	30	58
> $5000/MWh	2019-20	93	32	27	30	60
> $7500/MWh	2019-20	93	32	33	30	60
Reliability response	2019-20	93	52	33	30	185
> $300/MWh	2020-21 and beyond	42	6	4	0	14
> $500/MWh	2020-21 and beyond	78	11	11	1	46
> $1000/MWh	2020-21 and beyond	80	12	12	30	50
> $2500/MWh	2020-21 and beyond	86	25	19	30	58
> $5000/MWh	2020-21 and beyond	93	32	27	30	60
> $7500/MWh	2020-21 and beyond	93	32	33	30	60
Reliability response	2020-21 and beyond	93	52	33	30	85

Table 2 Winter DSP estimate for reliability studies (MW)

Trigger	Winter	NSW	QLD	SA	TAS	VIC
> $300/MWh	2020	42	6	4	0	14
> $500/MWh	2020	78	11	11	1	46
> $1000/MWh	2020	80	12	12	30	50
> $2500/MWh	2020	86	25	19	30	58
> $5000/MWh	2020	93	32	27	30	60
> $7500/MWh	2020	93	32	33	30	60
Reliability response	2020	93	32	33	30	160
> $300/MWh	2021 and beyond	42	6	4	0	14
> $500/MWh	2021 and beyond	78	11	11	1	46
> $1000/MWh	2021 and beyond	80	12	12	30	50
> $2500/MWh	2021 and beyond	86	25	19	30	58
> $5000/MWh	2021 and beyond	93	32	27	30	60
> $7500/MWh	2021 and beyond	93	32	33	30	60
Reliability response	2021 and beyond	93	32	33	30	60

2.5 Validation of DSP response

The reliability response projections were verified using the potential response information submitted to the DSP IP for each program included in the forecast, as discussed in Section 2.1. The comparison is shown in Table 3. In general, good agreement was found in all regions, with the reported potential response being generally lower than the estimate of current response (reflecting that not all DSP programs provided a potential response – see Appendix A).

The exception was Queensland, where the estimate is lower than the advised potential response. The Queensland potential response, however, includes a significant proportion of ONSG sources, which are excluded from the DSP forecast (as explained in Section 2.1), so AEMO finds the forecast also aligns well with reported potential for Queensland.

Table 3 Validation of summer DSP estimate for supply adequacy assessments

Trigger	Source	NSW	QLD	SA	TAS	VIC
Reliability response	DSP Summer 2019-20	93	52	33	30	185
Derived potential response	DSP IP	69	97	32	0	154
Difference	2019-20	24	-45	1	30	31

3. Forecasting future DSP

While AEMO's reliability studies only assume current levels of DSP (similar to only considering existing and committed generation is available to meet demand), AEMO's longer-term planning studies, like the ISP, use a forecast of how DSP may evolve in the future, and apply a scenario-based approach to the forecast contribution. Forecast DSP may include increased activities driven by new Rule changes, such as the AEMC's Wholesale Demand Response mechanism[8], or by technology uptake, for example through the proposal to make a range of appliance types capable of demand response through mandating Australian Standard 4755.2 for these[9].

For long-term planning studies, the DSP forecast is obtained by growing current DSP levels to meet an assumed level of activity by the end of the outlook period. This level:

- Is defined as the magnitude of DSP relative to maximum demand and linearly interpolated between the beginning and ends of the outlook period.
- Reflects scenario assumptions and state-specific features where necessary.
- Is determined through review and analysis of NEM and international DSP potential.

The ISP forecast of DSP also includes an estimated response of 150 MW from Queensland coal seam gas (CSG) facilities from 2019-20 (for the reliability response trigger only). This response is excluded from the 2019 ESOO, because it is not committed, nor has it been historically observed. Its inclusion in the ISP reflects AEMO's assumption that established CSG facilities now have the capability to reduce demand if incentivised, and the assumption this reduction would be triggered for prices observed under LOR 2 or 3 conditions.

3.1 Review of future DSP potential

In 2019, AEMO conducted a literature review of the potential for demand response in international energy markets, primarily the United States (US) and Europe. The review indicated that a DSP response magnitude of 8.5% of maximum demand (also adopted for the 2018 ISP) is a reasonable upper target for growth in DSP with appropriate incentives in place.

Further findings of the review indicated:

- Expanding existing best practice DSP, focusing on commercial and industrial programs, could feasibly achieve DSP potential of 9% of maximum demand, given that some US markets where demand response programs are advanced are already seeing participation levels between 2% and 10% of peak demand[10,11]. Some of these include battery storage, which is excluded from AEMO's DSP forecast because it is accounted for in the demand forecast and supply models.
- Reported current demand response potential, in markets where DSP is advanced, can range from 3% to 12%[12].

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[8] See https://www.aemc.gov.au/rule-changes/wholesale-demand-response-mechanism.

[9] See http://energyrating.gov.au/news/demand-response-update.

[10] FERC, 2009 Assessment of Demand Response and Advanced Metering, 2009, at https://www.ferc.gov/legal/staff-reports/sep-09-demand-response.pdf.

[11] FERC, 2018 Assessment of Demand Response and Advanced Metering, 2018, at https://www.ferc.gov/legal/staff-reports/2018/DR-AM-Report2018.pdf.

[12] ERCOT Annual Report of Demand Response (2019), at http://www.ercot.com/services/programs/load.

- DSP potential in European countries is estimated to be between 7.5% and 10%, with some outliers outside this range, and one estimate suggested the level was 9.4% for 34 countries represented[13,14,15].
- Large (five-fold or eight-fold) differences between current active DSP and future potential DSP may exist[16].
- Market structures (wholesale price market or capacity market) and DSP policy design (conditions on participation) play a role in incentivising or creating barriers to DSP.

3.2 Forecast calculation and assumptions

Figure 5 outlines how the future magnitude of DSP response (in megawatts) is calculated, based on the reliability response:

- Point A shows the existing level of DSP capacity. As explained in Chapter 2, this excludes embedded generation responses, because these are covered in AEMO's ONSG forecast.
- Point B shows existing DSP along with the typical contribution from ONSG at time of maximum demand.
- Point C is the target DSP level in the end year (in this case 2050). AEMO has created three different DSP uptake projections[17]:
  - High DSP – this is targeting DSP (including ONSG) equal to 8.5% of forecast peak demand.
  - Moderate DSP – this is targeting DSP (including ONSG) equal to approximately 5.5% of forecast peak demand.
  - Low DSP – this is maintaining the current level (in percentage) of DSP (including ONSG) in the market.
- Point D is the DSP percentage in the end year, excluding existing ONSG.
- The DSP reliability response for any years between points A and D is obtained through linear interpolation. This represents the forecast reliability response, and may include investments in new ONSG, although it excludes any investments in storage because these are modelled separately by AEMO.

Price response for any of the years is obtained by scaling the projection of the reliability response down to the price trigger bands, based on maintaining the same relative differences as the initial forecast year.

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[13] SIA Partners, Demand Response: A study of its potential in Europe, February 2015, at http://energy.sia-partners.com/demand-response-study-its-potential-europe.

[14] Gils, H. C., Economic potential for future demand response in Germany – Modeling approach and case study, Applied Energy 162 (2016) 401-415.

[15] Gils, H. C. Assessment of the theoretical demand response potential in Europe, Energy 67 (2014), 1-18.

[16] SEDC & RAP, Slides presented on Potential of Demand Response in Europe, Workshop on Demand Participation in Electricity Markets and Demand Response: Regulatory Framework and Business Models, 2017, at https://www.raponline.org/wp-content/uploads/2017/11/rap_sedc_rosenow_thies_fsr_slides_2017_oct.pdf.

[17] See Table 3 in AEMO's 2019 Forecasting and Planning Scenarios, Inputs and Assumptions report for how these are mapped to AEMO's five scenarios: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/2019-20-Forecasting-and-Planning-Scenarios-Inputs-and-Assumptions-Report.pdf.

Figure 5 Illustrating how future DSP is forecast

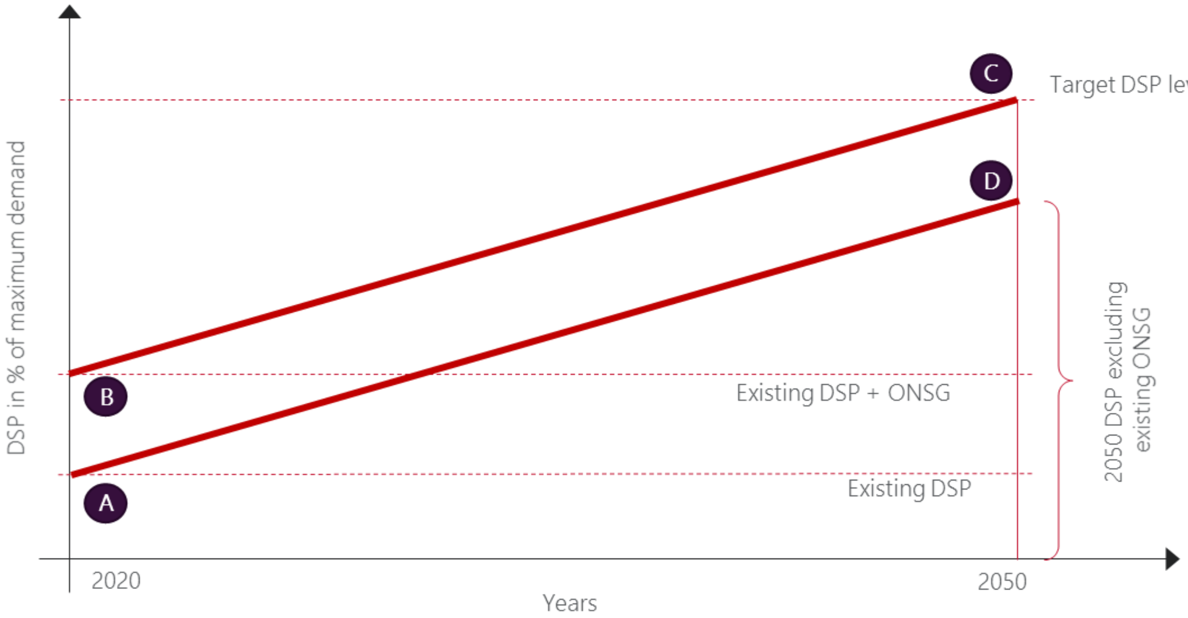

Table 4 below shows summer results for the moderate DSP projection in New South Wales. Full results for all regions are in the 2019 Inputs and Assumptions workbook[18].

Table 4 Forecast summer DSP (in MW) for New South Wales to 2050 – Moderate DSP projection

Trigger	2019-20	2029-30	2039-40	2049-50
> $300/MWh	41.5	108.5	195.4	294.3
> $500/MWh	77.8	203.5	366.3	551.7
> $1000/MWh	79.8	208.6	375.5	565.6
> $7500/MWh	93.2	243.8	438.9	661.1
Reliability response	93.2	243.8	438.9	661.1

[18] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/2019-Input-and-Assumptions-workbook.xlsx.

A1. Statistics

Table 5 summarises some aspects of information from submissions to the DSP IP in 2019. Note that 2019 was the first year where AEMO received responses from all relevant parties, so this data set is not directly comparable with previous years, and at this time a year-on-year change is not reported.

In total, 4,039,930 connection identifiers (NMIs) were submitted to the DSP IP, however some connections were listed in multiple programs (in some cases, single connections appeared in up to six programs). The number of distinct active connections in the DSP IP was 3,616,63.

Each program has a potential response field which can be filled out. Table 5 highlights that, in many cases, the potential response of the program is not known. This is a cause of DSP verification uncertainty.

Table 5 Program statistics grouped by program category

Category	Number of connections (connections may appear in more than one program)	Number of programs	Number of programs which included potential response information in submission
Connections on network event tariffs	2,593	1	0
Connections on retail time-of-use tariffs	1,184,151	31	1
Connections with energy storage	234,364	13	2
Connections with network-controlled load	2,545,015	62	58
Market exposed connections	1,268	24	5
Other	72,539	45	40

The types of connections reported to the DSP IP are mainly residential, however a significant portion of the connections were not specified. The load type categories are summarised in Table 6.

Table 6 Load types of reported connections

Load type	Number of distinct connections	Dominant program category in each load type as percentage
< not specified >	1,662,335	71% connections on retail time-of-use tariffs, 29% connections with network-controlled load
Aggregated	78	100% connections with network-controlled load
Commercial	2,602	99.7% connections on network event tariffs
Industrial	47	100% other
Residential	2,106,990	98% connections with network-controlled load

Table 7 lists the number of connections in each category, but also by DSP type. Of note, just over 2.5 million connections were reported to be on a network-controlled load program, engaging in load reduction. This number is primarily attributed to residential controlled load tariffs for water heating.

Table 7 also includes the sum of all reported potential megawatt responses of each program, including the ones excluded from AEMO's DSP calculation. In total, it suggests nearly 3,572 MW of potential response exists, with more unquantified or unknown. This represents approximately 10% of peak NEM demand. Some quoted potential responses, however, may represent rated capacities or typical demand levels, and may not be fully realised in practise.

Further analysis is necessary to determine the magnitude of the difference between actual and potential response of these programs, and understand how program design affects the response in aggregate.

Table 7 Number of connections grouped by program category and DSP type

Category	DSP type	Distinct number of connections	Reported sum of potential response (MW)	Number of programs
Connections on network event tariffs	Load reduction	2,593	Not reported	1
Connections on retail time-of-use tariffs	< not specified >	1,173,980	Not reported	30
Connections on retail time-of-use tariffs	Embedded generation	15	1.8	1
Connections with energy storage	< not specified >	10,054	Not reported	9
Connections with energy storage	Energy storage	112,155	0.2	2 out of 4
Connections with network-controlled load	< not specified >	0	Not reported	3
Connections with network-controlled load	Embedded generation	6	11.0	1
Connections with network-controlled load	Load reduction	2,545,004	2,624.0	57 out of 58*
Market exposed connections	< not specified >	964	Not reported	19
Market exposed connections	Embedded generation	20	36.9	4 out of 4
Market exposed connections	Load reduction; embedded generation	258	109	1
Other	< not specified >	35	49.2	3 out of 4
Other	Embedded generation	39	95.8	16
Other	Energy storage	758	4.5	2
Other	Energy storage; embedded generation	0	4.0	1
Other	Load reduction	71,705	605.5	17 out of 21
Other	Load reduction; embedded generation	2	30.0	1

* Analysis of this sub-category suggested 49 program potential responses were duplicated, leading to the total reported potential response being 14,400 MW too high. The megawatt value in the table reflects the adjusted amount.