Meeting Date: 16 March 2023

SYSTEM OPERATOR PAPER ON DEMAND RESPONSE

SECURITY AND RELIABILITY COUNCIL

This paper introduces a paper from Transpower, as system operator, on how they model and respond to changes in electricity to manage the power system and support security and reliability of electricity supply.

Note: This paper has been prepared for the purpose of the Security and Reliability Council (SRC). Content should not be interpreted as representing the views or policy of the Electricity Authority except where specifically noted.

Demand Response – modelling and responding to changes in demand

1.1.1 The SRC has asked the secretariat to provide information on demand response, as part of the SRC's demand response theme for the Q1 March 2023 meeting.

1.1.2 As part of a suite of papers, the secretariat has arranged for a paper and presentation from the system operator including how the system operator models and responds to changes in demand, how they will manage demand response and how demand response will be included in future security of supply assessments.

1.1.3 The system operator paper (appendix A) focuses on the key risk areas, including where solutions are in place or planned.

1.1.4 The system operator considers demand response from (and has based its analysis and commentary on) the perspective of what it sees at grid exit point (GXP) level. This is due to the local distributors having the visibility and control of the effect of individual consumers' DER within the distribution network.

1.1.5 The paper outlines the system operator's approach of considering demand over different time horizons (years, months, weeks, days, real time) and the relevant inputs (information) the system operator uses at stages in its assessments.

1.1.6 An example of a key input used in the system operator's analysis is *distributor electricity demand forecasts*. Given the importance of this variable input and the variation in distributors' abilities to forecast demand, members may wish to enquire how the system operator addresses inaccuracies, particularly for time horizons of days or real time, and what long term solutions to the issue of inaccuracy may be necessary.

1.1.7 The system operator believes an increasingly critical component of forecasting demand is the inclusion of embedded generation where generation assets are connected to the distribution network, not the grid, and therefore not individually visible to the system operator beyond the aggregated effect seen at the GXP level. Transpower's necessary reliance on information from distributors (and distributors' reliance on information from embedded generators, retailers and metering equipment owners (MEPs) on their networks) means there is risk in the accuracy and timeliness of such information.

1.1.8 Of the various types of embedded generation, the system operator paper notes only domestic solar is currently forecast, with other types of embedded generation assumed to remain at current levels, unless the system operator is informed otherwise. Members may wish to think about what further safeguards or information flow is needed to support greater visibility and accuracy and the potential burden of this on participants may be addressed.

1.1.9 The system operator paper (at page 12) responds to a question posed about what roadblocks or hurdles the system operator has experienced. This section provides a level of assurance the system operator is turning its mind to the important issues impacting demand response and acknowledges where there may be gaps. Members may wish to consider further questions about these challenges and raise them at the meeting.

1.1.10 Representatives from the system operator team will present and be available for questions.

Questions for the SRC to consider

The SRC is asked to consider the following general questions.

Q1. What further information, if any, does the SRC wish to have provided to it:

- **a. About demand response in future system operator reporting?**
- **b. About how the Authority can best support the system operator's role in ensuring the appropriate visibility of demand response?**

Q2. What advice, if any, does the SRC wish to provide to the Authority?

Appendix A: System operator paper – Demand Response

Meeting date:	16 March 2023
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Security and Reliability Council Paper

How the system operator models and responds to changes in demand

1 Purpose

The purpose of this paper is to respond to the Security and Reliability Council's (SRC's) request to hear about the system operator's role in demand response. This paper will cover the following topics:

- Available tools and how they will work to manage demand response
- How distributed energy resources (DER) will be included in future security of supply annual assessments (SOSAs), and their impact on SO systems and processes, and the power system generally
- Potential Code changes that may be needed to support demand response and why
- System operator modelling and/or its view on the impact on demand (capacity and energy) if domestic supply of LPG is banned or reduced as part of CCC recommendations or response.

The SRC seeks a relatively **high-level paper and presentation**, focusing on the key risk areas, where solutions are in place or planned and where learnings and opportunities arise.

2 Evolving demand response

For the purpose of this paper, we will consider demand as what is seen by the system operator at GXP level. The behaviour or response of demand is evolving, becoming more dynamic and less predictable. Drivers of this change include:

- More injection from distributed energy resources not dispatched today via the market system, i.e. distributed generation typically less than 10 MW in size such as solar PV and batteries.
- Increasing electrification such as electric vehicle uptake, process heat conversion, etc.
- Changing consumer behaviour – smart homes, time of use retail plans, streaming entertainment etc.
- Removal of regional coincident peak demand (RCPD) charges, and other government policy or regulatory changes such as healthy homes.

- Future development of flexibility services by industry.

3 System Operator considers demand response over different time horizons

As part of operating a secure power system, the system operator considers demand over a range of time horizons, from years-ahead through to real-time. The following sections discuss demand consideration across these different time horizons.

3.1 Time Horizon: Years

Annual security of supply assessment (SOSA): 10-year assessment (latest 2022 to 2031)

The SOSA assesses the winter energy and capacity margins over a 10-year period. To undertake this assessment, we use a forecast of winter energy and winter capacity demand.

The demand forecast is prepared by Transpower and uses a 3-stage modelling approach as shown in Figure 1.

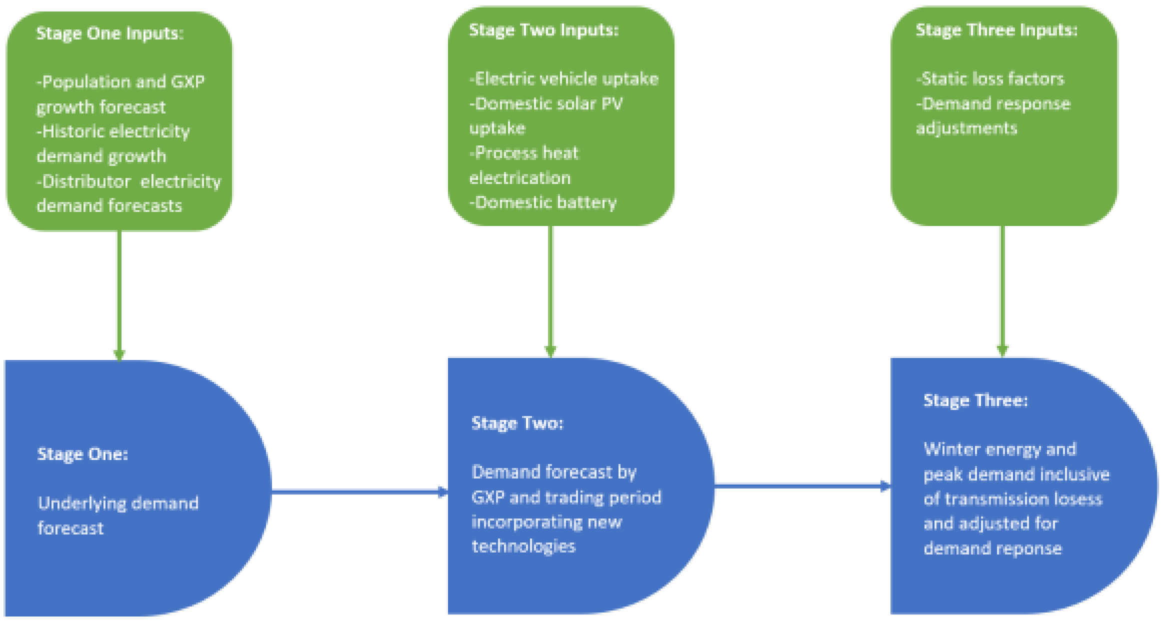

Figure 1 – Overview of the demand forecasting process for the SOSA

Stage one: Forecast underlying demand growth rate

This stage forecasts the underlying demand growth rate. Inputs to this forecast include expected changes in population and Gross Domestic Product, historic demand growth rates, and demand forecasts from network companies (distributors). The demand forecasts from distributors will include a variety of contributing factors to the demand growth they are anticipating on their networks such as potential gas-to-electric conversion.

Stage two: Add changes in demand from new technologies

In this stage, demand changes for electric vehicle charging, domestic solar PV, domestic batteries and process heat electrification are added in, taking into consideration the regional, seasonal and sectoral impact of these technologies. We consider how some technologies alter the demand for electricity within a typical day. For example, we assume that some electric vehicle charging is smart[1] and these will be set up to charge electric cars during periods of low demand.

While the demand forecasts consider embedded generation, only the uptake of domestic solar PV is forecast[2]. Other types of embedded generation are assumed to remain at current levels, as derived from historic market information. Adjustments are made for other embedded generation if we are informed of changes by distributors or customers.

Different forecast uptake rates for these new technologies in this stage are considered. An example of these uptake rates[3] for our 2022 SOSA is shown in Table 1. Outputs from this stage are forecast demand - and its components - broken down by grid exit point (GXP) and half-hourly trading period.

Table 1 – Stage 2 technology uptake rates as used in the 2022 SOSA

Demand scenarios	Whakamana I Te Mauri Hiko (WiTHM) Scenario	Description
Low Demand (Sensitivity)	A blended mix of Business as Usual and Measured Action with greater EV update	Some electrification of transport and process heat fails to emerge as compared to the medium and high demand sensitivities. This may reflect stalled technology development or if regulatory settings do not achieve their intended goals. It could also be consistent with a future where other alternatives to decarbonisation are pursued, such as forestry abatement
Medium Demand (Reference Case)	Accelerated Electrification with greater EV uptake	Technology uptake rates represent a realistic yet aspirational scenario for the New Zealand economy and electricity industry. This will require integrated, coordinated planning and action from across the economy and government.
High Demand (Sensitivity)	Mobilise to Decarbonise	There is a much stronger and more urgent response to climate change. It is not the rate of development of technologies that will change under this scenario, but rather the strength of the decarbonisation effort. While this scenario has more domestic solar uptake, it has little impact on reducing the winter peak demand.

[1] In this context smart electric vehicle charging refers to technology that avoids electric vehicle charging during peak demand or high price periods.
[2]Domestic solar PV could increase as the number of households increase, as well as greater proportion of households adopting solar PV.
[3] The Whakamana i Te Mauri Hiko (WiTMH) scenarios are leveraged to create these uptake scenarios.

Stage three: Calculate winter energy and capacity demand

For this final stage, the forecast winter energy and peak demand are calculated.

Winter energy demand is calculated by summing the stage two forecast demand, over each GXP in both islands, and over each winter half-hour period. Winter peak demand is calculated by averaging the stage two forecast demand, over each island, and over the highest 200 half-hours of winter daytime demand[4].

Forecast winter energy and peak demand, as used in our assessment, is on a gross basis, includes transmission losses and is adjusted for demand response[5]. This gross demand can be thought of as the total demand seen by the national grid and distribution networks. It is the demand served by both embedded generation and grid-connected generation.

The above description of the load forecast process as used in the SOSA is included in our report (section 4.1). It and further details on the SOSA and its results can be found here.

Demand sensitivities

There is uncertainty in how some of the assumed conditions could unfold over the next decade. To capture this range of uncertainty, we consider a number of supply and demand-side sensitivities in the SOSA. In regards to the demand-side sensitivities, we consider:

- Different demand growth rate scenarios which include different rates of uptake of DER resources (as outlined in Table 1)
- The potential exit of Tiwai aluminium smelter
- The impact of step changes in demand such as new data centres, industries or electrification of process heat not captured in the above scenarios
- The potential impact of reduced demand response at peak times due to the removal of the RCPD transmission charge

System security forecast (SSF): 3-year assessment (latest 2023 to 2025)

The SSF reports on any risks to the system operator's ability to meet the Principal Performance Obligations (PPOs) over the ensuing 3-year period, considering existing and committed grid and generation assets. The latest SSF can be accessed here.

The demand forecast used in this SSF uses the same method as the Transmission Planning Report "expected" forecast prepared by Transpower. The forecast represents an expected forecast that can be interpreted as a 50% probability of exceedance. The same three-stage method as outlined in the SOSA section above is used to derive the demand forecast.

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[4] This calculation of winter peak demand (also called the H100 demand) for use in the winter capacity margin calculation is specified in the Security Standards Assumptions Document and makes allowance for demand response due to high prices and at peak times.
[5] This is applied to both the winter energy and winter capacity margin assessments.

3.2 Time Horizon: Months

New Zealand Generation Balance (NZGB)

NZGB uses historical data to anticipate expected worst-case peak load during the forecast period. Since the primary purpose of NZGB is to assess generation requirements, generation and HVDC transfer data are used in the forecast calculation (as this will ensure losses are accounted for when determining generation requirements). The load forecast calculation looks at historical peaks, considering period of the year, day of the week (or any public holidays), and period of the day (morning / evening peak).

A base forecast which we call the 'long-term forecast' is developed based on the maximum load in a four-week window from the same period in the previous year; a growth assumption of 2% is applied to this forecast.

We also use a 'short-term forecast' for comparison based on the maximum load over the previous three weeks; no load growth assumption is applied to this forecast.

Shortfalls seen in NZGB result in a Customer Advise Notice (CAN) being issued, to encourage generators to reconsider outages, to be available to offer and to signal to demand to provide bids.

NZGB can be accessed here.

Outage security assessments

Outage security assessments use historical data to anticipate expected load in the assessment period. Load is forecast by looking at historical peaks, one week either side of the assessment date. The highest peak from the past three years is used as the forecast load for the upcoming outage.

There is no load growth assumption applied to this data as we assess outages in a number of timeframes, including within weeks of the outage. We are able to run scenarios based on peak loads we are seeing closer to when the outage is being carried out.

Based on the outage security assessments, we consider requirements to enable outages to proceed. These may include voluntary requests for distributors or directly connected customers to manage load, mainly during peaks.

Assessment of Winter 2023

The system operator undertook a winter capacity review and provided an assessment of the potential system capacity requirements for winter 2023 under different supply scenarios. Further details can be found here.

In this analysis, increasing peak demand was identified as one of the contributing factors to the increasing winter capacity issues observed in recent years (2021 and 2022). Figure 2 shows the top 20 daily peaks each year from 2010 to 2022. It shows that peak demand has been growing strongly over the last two years.

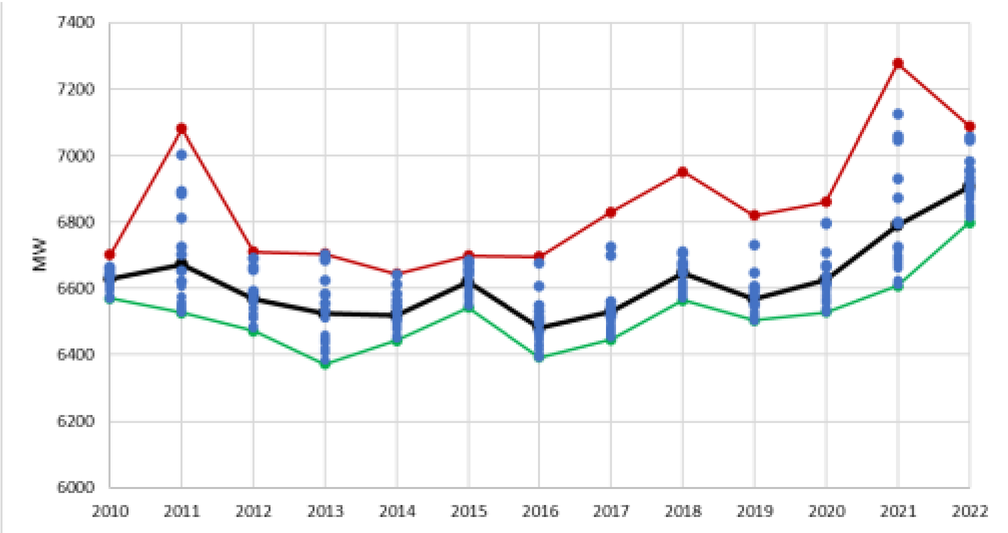

Figure 2 - Top 20 daily peak demand each year from Jan 2010 to Sep 2022

This winter peak capacity analysis considered the market conditions on peak load days and assessed the potential capacity risks under different scenarios of inflexible thermal commitment and wind generation. The demand response active during those peak load days (i.e. load responding to price signals) was included within the analysis. Furthermore, any demand response offered as interruptible load reserves[6] on those days was included.

The winter analysis demonstrated the need for additional flexible capacity if slow-start thermals are not offered into the market. Slow-start thermal units are inflexible unless they are already generating. This requires sufficient market signals to provide a commercial incentive for slow-start units to start-up to meet peak demand. If slow start thermals are not offered, there is an increased risk of generation shortfalls during Winter '23, which may require the system operator declare a Grid Emergency and reduce demand.

3.3 Time Horizon: Days

System operator load forecast

The use of load forecasts is critical in the market as it provides valuable information for decision-making and enables effective communication between the system operator and market participants. However, forecasting demand has become increasingly complex and uncertain due to the growing adoption of new technology and electrification in response to the need for action on

[6] Interruptible load reserves in addition to generator reserves are used to supply the contingency reserve requirements on the power system.

climate change. While no forecast can be entirely accurate, having a dependable forecast is essential for the system operator and market participants to better understand and prepare for potential future conditions.

In forecasting demand response, two steps are involved: load without demand response and load with demand response.

Load without demand response is forecasted in half-hour blocks, looking ahead 14 days. The forecast is divided into seven regions, which are further broken down into each GXP. These seven regions are then aggregated to form a forecast at an island and national level. It is important to note that the load forecast does not include losses, as this is calculated in the market system.

Transpower has the option to import the load forecast from a service provider or use the forecast tool embedded in its SCADA system. After completing a tender and forecasting accuracy trial in 2021, Transpower is currently using Tesla Load Forecasting as its forecasting service provider. Tesla's load forecast is provided at the regional level using algorithms that self-adjust to actual loads. The key inputs for the forecast are historical load and five weather variables, including temperature, humidity, cloud cover, wind, and rain. Through Tesla's online web interface, the system operator can access an analysis of the impact each variable has on the load.

Small-scale demand response is included in the load forecast through the load history. This captures lots of small-scale demand response that consistently responds to time-of-use or periods of elevated loads. Although the expansion of DER responding to a range of different inputs is expected in the future, it currently does not impact load forecast accuracy and therefore does not require a specific variable beyond load history. By using load forecasts from international forecasting specialists such as Tesla Load Forecasting, models can quickly be adjusted to include any number of future variables by utilising their expertise in jurisdictions with higher levels of DER.

Load with demand response includes large-scale demand response that cannot be forecasted using historical demand profiles. This is undertaken in the scheduling and optimisation of resources in the market system. This process produces an optimised forecast generation to meet demand (including demand response) and prices called Forecast Schedules. The Schedules produce a 7-day forecast once a day (WDS), a 36-hour forecast every 2 hours (NRSS), and a 4-hour forecast every 30 minutes (NRSS). The schedules are based on offers of generation, large-scale demand response based on bids of load, and the load forecast produced by Tesla.

All demand response bids are estimates provided directly by the relevant participants. There are three types of bids: dispatch bids, non-dispatch bids, and difference bids. Dispatch bids are firm committed resources for balancing the system, non-dispatch bids are indications of load consumption depending on spot price outcomes, and difference bids are voluntary indications of price-responsive load at GXPs, which already have a load forecast.

3.4 Time Horizon: Real-time

Demand participation through dispatchable demand products

Voluntary, active demand participation in the wholesale market is planned to be delivered through the Real Time Pricing (RTP) project, at the end of April 2023. This will deliver two types of wholesale demand participation: enhancements to the real-time Dispatchable Demand (DD) and the new Dispatch Notified Load (DNL) product, where participants may signal their intent for price-responsive demand reduction. DD and DNL are essentially implemented the same way: participants bid in half-hourly volumes of energy to consume at various price points, which function the same way as generator offers in the optimisation process. If the DD/DNL bid tranche is the next resource in the stack of dispatchable resource bids/offers, the participant is dispatched to reduce their consumption to the optimum level determined by the market solver.

DD participants are required to provide real-time telemetry to monitor compliance with these instructions; in return, if they are dispatched outside the merit order (or if the half-hourly settlement price deviates significantly from the dispatch price) they are entitled to receive constrained costs and be made whole according to their bids.

DNL is intended for smaller participants (less than 30 MW) for whom the cost of providing real-time telemetry is too burdensome. These participants are not eligible for constrained costs.

DD/DNL participants are not paid for their load reductions. They benefit from the avoidance of cost of wholesale prices they were not willing to pay for their consumption. As most consumers are on fixed-price contracts, DD and DNL participants are expected to be either direct spot price-exposed consumers or retailers with demand response capability seeking a physical hedge.

Managing scarcity pricing situations

Where the amount of offered dispatchable resources (either generation or dispatchable demand) is insufficient to meet the scheduled load, an energy shortfall will occur, which may necessitate demand management (involuntary load reduction). An energy shortfall results in the Scheduling, Pricing, and Dispatch (SPD) tool being unable to derive a marginal price according to dispatchable resource bids or offers. In this circumstance, an administered scarcity price is applied to the amount of energy that is not scheduled to be served. The energy scarcity price tranches are set by the Authority and stipulated in the Code and vary according to extent of shortfall. Similarly, the instantaneous reserve shortfall is valued with its own set of scarcity price tranches.

When the system operator instructs involuntary demand reduction, the real-time telemetered load in the dispatch schedule drops to a point where marginal pricing succeeds. However, this is not reflective of the value of lost load. To ensure dispatch prices (and subsequently settlement prices) reflect the value of lost load, “what-if” pricing is used during demand reduction periods. The “what-if” price is determined by running a parallel dispatch schedule solve, with an uplift in load based on the short-term load forecast at the time of the demand management instruction.

Managing a capacity shortfall situation

Where insufficient generation offers and demand response results in, or will likely result in, an inability to supply load and maintain n-1 security, the system operator will issue a notice to participants (CAN, WRN or GEN depending on the expected time to the event). Leading up to gate closure, the system operator (if time permits) will contact the largest distributors to determine how much controllable load is available. Because there are 29 distributors it is not practical or feasible to establish how much total controllable load is available to be shed when in a grid emergency situation requiring load reduction. Instead, it is pragmatic to instruct the largest distributors to shed whatever controllable load is available to resolve the situation.

Once a grid emergency is declared (within one hour of gate closure), the system operator will instruct the shedding of controllable load not offered as interruptible load. In 2022, the system operator successfully managed two grid emergency situations using controllable load[7]. Although the general industry interpretation of the rights available to the system operator in a grid emergency include requesting participants to reduce controllable load (and the system operator GENs “request” rather than “instruct” the reduction of controllable load), which relies on distributors reducing controllable load when requested, the Electricity Authority has indicated to the system operator that it could take a broader interpretation of the Code to issue controllable load instructions.

Upper South Island load manager

Eight Upper South Island (USI) distributors cooperate to manage their controllable load on the USI transmission network. The Upper South Island Load Manager (USI LM) is located at Orion’s control centre based in Christchurch and operated by Orion on behalf of all USI distributors. Originally the main purpose of the load manager was to minimise peak loads and hence reduce the peak-related transmission charges that distributors used to pay under RCPD charging basis.

In addition to the ability of the USI LM to manage peak demand, the system operator interfaces with the USI LM as part of managing voltage stability in the USI under high load scenarios during outages. Where a voltage stability issue is identified the system operator can send an instruction to Orion which results in the shedding of controllable load in the USI as required to minimise the voltage stability issue.

Other real-time demand responses

Should a contingent event or extended contingent event occur, then automatic demand reduction in the form of interruptible load (paid and scheduled ancillary service) and/or automatic under-frequency load shedding (AUFLS), the latter being an obligation on distributors and direct connects in the North Island, and the grid owner and Tiwai in the South Island to reduce demand by up to 32%, may occur to restore the balance between supply and demand.

[7] Note the system operator issued 13 low residual CANs in 2022.

4 Future System Operator considerations for demand response

Demand-side management will play a key role in integrating intermittent renewable generation and addressing New Zealand's peak demand challenge, particularly as intermittent generation increases in line with efforts to decarbonise the economy. Transpower has identified the development of DER markets as one of the four key pillars for enabling effective demand-side management in WiTMH.

Network companies at both transmission and distribution level, as well as retailers and aggregators, are already exploring the value of using DERs to provide flexibility services. Transpower is actively engaged in the Flex Forum initiative, sits as an observer in the Energy Networks Association's Smart Technology Working Group, and engages with organisations across the market and internationally who are working in this space.

The system operator's most recent thinking on demand response/flexibility services was shared in December 2022 via the paper '*Enabling distributed flexibility to support whole system reliability and efficiency: a system operator view*'. A copy of that paper can be found here.

The following sections provide responses to the questions asked by the SRC that are relevant to the system operator.

- **SRC question 1:** *How DER will be included in future SOSAs, its impact on SO systems and processes and power system generally*

  In regards to the SOSA, the above process outlines how DER (including demand response) is included in the preparation of the SOSA demand forecast and included as part of the SOSA assessment. This process will be followed in our upcoming 2023 SOSA. For our 2023 SOSA, we are seeking additional demand response information from electricity distribution businesses to explore a sensitivity with additional demand response[8].

  As discussed above, DER has the potential to impact the accuracy of our real-time load forecast as uptake increases. We continue to monitor accuracy and take steps to adjust our approach as required.

  The implications of DER to the power system in general have been well-documented in several system operator technical reports,[9] as well as in the Future Security and Resilience (FSR) work completed for the Authority. Challenges such as fault ride-through performance,

[8] We sought this information for our 2022 SOSA but did not receive sufficient response to generate a sensitivity.

[9] Reports have investigated operational implications of high uptake of DER such as solar PV, batteries and electric vehicles. These reports can be found on the Transpower website here.

visibility, coordination, and displacement of grid and synchronous generation are being considered under FSR.

- **SRC question 2:** *System operator modelling and/or its view on the impact on demand (capacity and energy) if domestic supply of LPG is banned or reduced as part of CCC recommendations or response*

  In regards to the long-term demand forecasts used in the SOSA and SSF, information is sought from distributors on expected demand growth in their networks as part of the demand forecast methodology (Stage 1). This increased demand on their networks would be due to a combination of factors including electricity vehicles and gas-to-electric conversions[10].

  In addition to residential gas-to-electric conversion the forecast also considers the potential impacts of industrial process heat electrification.

- **SRC question 3:** *System security – how the SO can tap into demand response in an emergency?*

  The section above on managing a capacity shortfall in real-time outlines our current process to access controllable load during a grid emergency. This is a manual process that relies, to some extent, on the goodwill of industry participants to reduce controllable load when requested.

  With release of enhanced DD and the new DNL products this year, we may also see an increased role for demand in managing tight supply situations, provided sufficient demand is bid into the market.

  Other forms of demand response can be triggered during a contingent or extended contingent event when frequency falls to restore the balance of supply and demand. These are automatic responses and include interruptible load and AUFLS.

- **SRC question 4:** *To what extent can Demand Response support our capacity/peaking challenge?*

  We have seen during Grid Emergencies over the last winter period that controllable load is a valuable tool to help manage the present capacity/peaking challenge. On that basis, we

[10] Discussions with some distributors s have highlighted these as potentially major contributions of future demand growth.

believe that demand response is a valuable tool in managing capacity/peaking challenges if enabled.
We do note that system operator still has a lack of visibility of the amount of controllable load. Traditionally, this controllable load has been provided by distributors, who have less incentive to maintain given the removal of RCPD.

- **SRC question 5:** *Are there any roadblocks or hurdles the system operator has experienced?*

  To date we have limited experience in the use of a specific demand response or flexibility product. However, key considerations we have shared with industry include:

  - Whole system visibility is key to security and efficiency - Information and data sharing between flexibility service providers, distribution networks, and the system operator will be critical in ensuring overall system security and increasing efficiency for consumers.

  - Whole of system coordination is key to security and efficiency - Coordination between parties issuing dispatch instructions to flexibility providers is needed to maintain a secure and stable power system.

  - Use existing data standards and interfaces where possible - Flexibility services interacting with the system operator and wholesale market should use the existing system operator interfaces

  - Market participants control their assets - Flexibility services providers offering their asset capability to the system operator will need to implement dispatch instructions received from the system operator.

  - Ancillary services are designed to meet system needs - Ancillary services procured by the system operator are designed to keep the power system within the required operating parameters. New or enhanced ancillary services may be required in the future as the power system evolves.
  - Services require proof of performance - Flexibility service providers will continue to need to provide proof of performance to the system operator. The level of proof should be commensurate with the risk that non-performance poses to the power system.

  - Market design reflects the underlying physical electricity system - The wholesale electricity market for energy is nodal to reflect the physical attributes of the national transmission grid. Ancillary service product markets are national (instantaneous reserve), island-based (over-frequency reserves, black start, and frequency keeping), and zonal (voltage support).

- **SRC question 6:** *If the same DER is captured by two different purposes, how do you reconcile the potential conflict?*

  In order to reconcile the potential conflict, buying parties would have to have visibility that the DER is being offered for two different purposes. The parties could then coordinate to determine if there is a conflict, and if there is, then the DER asset owner or trader would need to decide what purpose to offer the DER for.

  Industry could also look at how to integrate distributed energy resource management systems to provide coordinated whole-of-system operations, using DER where it is most valuable.

  Without visibility, should a conflict occur and offered DER underperform when called upon, then compliance avenues would need to be pursued. The consequence of this compliance avenue would need to be sufficient to deter repeat breaches.

- **SRC question 7:** *Potential Code changes that may be needed to support demand response and why*

  Extensive Code change will be required going forward to fully enable demand to play its role in the operation of an efficient, secure and resilient power system. What these Code changes will be will depend on the path taken to enable greater demand response, be that obligations on asset owners or the development of products and services.

- **SRC question 8:** *Available tools and how they will work to manage demand response*

  As discussed above the market system changes delivered through the Real Time Pricing project will enable greater demand response, including from DER.

  Should demand response products or services be developed in the future, we would consider how we could use existing data standards and interfaces where possible.