



TRANSPOWER

# Energy Security Outlook 101

A document to support understanding of the monthly Energy Security Outlook, including the Electricity Risk Curves and Simulated Storage Trajectories.

Version: 3.0

**Date:** 28 May 2026

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## IMPORTANT

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# Version History

Version	Date	Change
1.0	15 April 2024	A merged and refined ERC101 document combining the previous 'SOS 101s' series. Also reflects updated changes to the ERCs and operational processes and SO obligations following the SOSFIP update in June 2023.
1.1	22 August 2024	More information on an increased buffer for September-October 2024, and refinements on wording around the floor and buffer.
2.0	30 May 2025	Repurposed ERC101 document to ESO101. More of a holistic view of ERCs, SSTs, regulatory requirements, etc.
3.0	28 May 2026	Update to include SOSFIP (effective 1 May 2026) changes.

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# 1 Purpose

1. The Energy Security Outlook (**ESO**) is published monthly by the System Operator and provides two important security of supply indicators: the Electricity Risk Curves (ERCs) and the Simulated Storage Trajectories (SSTs). Together the ERCs and SSTs provide a view of potential future energy security in New Zealand's electricity system, into the next 1-2 years.
2. The purpose of this document is to help participants better understand the ESO including the role of ERCs and SSTs within the electricity industry's security of supply forecasting and information framework, and the assumptions behind them. It also covers other important elements of the security of supply framework such as the Risk Status and the actions it triggers, and contingent storage access arrangements.

## 2 Introduction to the Energy Security Outlook

### 2.1 Purpose of the Energy Security Outlook (ESO)

3. The purpose of the Energy Security Outlook (**ESO**) is to provide information to electricity industry participants and other stakeholders about the energy security outlook into the next 1-2 years. In addition, the parameters within the ESO are used, at times of heightened risk of energy shortage, to trigger actions to mitigate the risk of running out of controlled hydro storage.
4. The key parameters the ESO uses to signal energy risk are the:
  - Electricity Risk Curves (**ERCs**), which model a calculated percentage risk of energy shortage, and are used to trigger Risk Status levels,
  - Simulated Storage Trajectories (**SSTs**), which project potential future hydro storage trajectories, and
  - actual hydro storage trajectory and position.
5. The ESO is published monthly, to provide up-to-date information with the intention to inform a market response by industry participants. This contributes to mitigating the risk of future energy shortage, by allowing time to coordinate assets and fuels to maintain security of energy supply at all times.
6. While energy shortage situations can give rise to capacity risks, the System Operator uses other tools to monitor and mitigate capacity risks. These include the New Zealand Generation Balance (**NZGB**),<sup>1</sup> monitoring 'residual' generation offers,<sup>2</sup> monitoring storage levels and inflows for each of the key controlled storage hydro lakes including all those with contingent storage, power system analysis for regional security of supply issues, and ongoing engagement with generators to ensure its intelligence about operational capabilities and constraints remains current.

### 2.2 Regulatory framework for the ESO

7. The Security of Supply Forecasting and Information Policy (**SOSFIP**) sets out the rules with which the System Operator must comply in calculating and publishing the ERCs and SSTs.<sup>3</sup>
8. The SOSFIP is a system operation document approved by the Electricity Authority (**Authority**) and incorporated by reference into the Electricity Industry Participation Code (the **Code**). The SOSFIP describes how the System Operator prepares and publishes information to assist participants to manage security of supply risks.

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<sup>1</sup> See [NZGB website](#)

<sup>2</sup> [Invitation to Comment: Low Residual Review Consultation \(Closed\) | Transpower](#)

<sup>3</sup> See the current [SOSFIP](#)



called the Contracted Fuel Case and is discussed further in section 10. The Base Case ERCs and SSTs are discussed in the remaining sections.

13. The SOSFIP also sets out the basis for triggering further actions if the industry response has not sufficiently mitigated the risk.<sup>6</sup>
  - The first step (at Watch status) requires the System Operator to increase the frequency and span of security of supply information and forecasting it provides to signal the heightened energy risk to industry.
  - If the industry response does not arrest falling hydro storage levels, access to extra water storage in Lakes Pūkaki, Tekapo and Hāwea is triggered at Alert status. Resource consents for these catchments permit generators to access more water only when it is needed to mitigate an electricity supply emergency (**contingent storage**).
  - If hydro storage levels continue to fall, then the System Operator may be required to initiate an Official Conservation Campaign (**OCC**) asking New Zealand households and businesses to voluntarily reduce electricity consumption (Emergency status). Additional contingent storage at lake Pūkaki is available under an OCC.
  - If these actions still do not resolve the risks, the last resort action is for the System Operator to instruct rolling outages that will turn off electricity supply for short periods at different locations around the country on a rolling basis. This is covered in the System Operator Rolling Outage Plan (**SOROP**).<sup>7</sup>
14. This regulatory framework prioritises a market-based industry response that ensures other fuel sources are utilised to the extent practicable, before accessing contingent storage. This is intended to provide time for inflows to arrive in the form of rain and snow melt, and holds back some hydro storage against the risk of unplanned outages affecting other generation assets during an extended dry period.

## 2.3 Overview of the ESO

15. The ESO is used to assess the risk of energy shortage in New Zealand, and the South Island on its own.<sup>8</sup> It shows how actual hydro storage and projected hydro storage (simulated as SSTs) are tracking relative to a calculated risk of energy shortage (modelled as ERCs). The risk of energy shortage is considered as the risk of running out of controlled hydro storage in the next 12 months, inclusive of contingent storage.<sup>9</sup>
16. Figure 2 below shows the Watch ERC (yellow), Alert ERC (orange) and Emergency ERC (red)<sup>10</sup>, the portion of controlled hydro storage that is contingent storage (purple), simulated storage trajectories (SSTs) and actual hydro storage levels (black line).

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<sup>6</sup> While the basis for the trigger is set in the SOSFIP, some of the actions are covered in the [Emergency Management Policy](#), Part 9 of the Code and SOROP. All triggers are on the Base Case curves.

<sup>7</sup> [System Operator Rolling Outage Plan – effective September 2024](#)

<sup>8</sup> We consider South Island risk on its own as its largely supplied by hydro lakes. In an extended period of low inflows, when hydro lakes are running low to conserve storage, the South Island supply will be supplemented by North Island thermal generation, via the HVDC interisland link which has firm limits. Thus, we take these considerations into account.

<sup>9</sup> Also known as available storage, the hydro storage lakes modelled in the ERCs are lakes Pūkaki, Tekapo, Manapouri, Te Anau, Hāwea and Taupo. Storage in lakes Pūkaki, Tekapo, and Hāwea, include some storage (contingent storage) which under resource consents is only accessible in an electricity supply emergency situation.

<sup>10</sup> Shown as the solid yellow, orange and red lines which are the envelope to the shaded area of the corresponding colour.

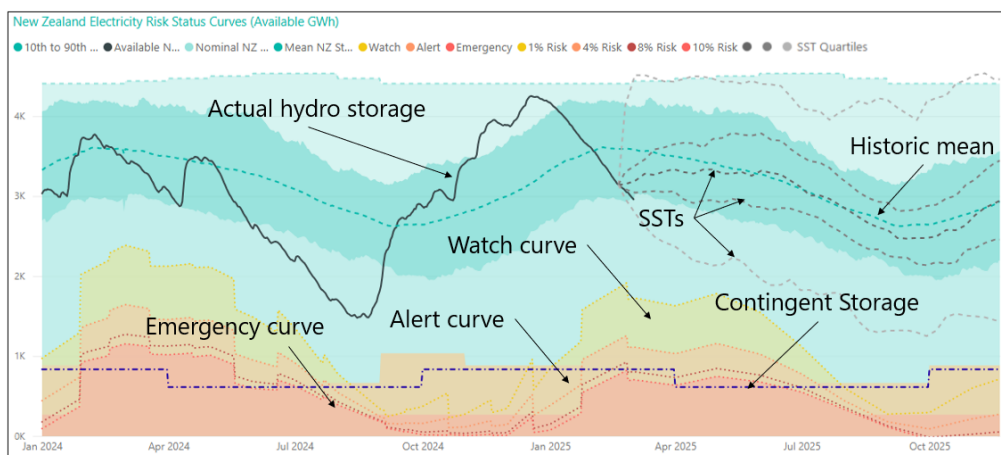


Figure 2. New Zealand ERCs and SSTs (percentiles) labelled (GWh).

17. The Watch, Alert and Emergency ERCs reflect different percentage risks of running out of controlled hydro storage (1%, 4% and 10% respectively) or the contingent storage release boundary, whichever is higher. Watch, Alert and Emergency status are triggered if actual controlled hydro storage crosses the relevant ERC.
18. The ESO is available on the [Transpower website](#) and updated monthly to include up-to-date information in the modelling, or more frequently as required when security of supply risk increases.

## 2.4 Risk Status

19. The risk status indicates to the industry the level of risk to energy security of supply we are facing currently. Different risk status' trigger certain actions for System Operator or industry participants, to help manage the risk. A status is triggered by actual storage dropping below the corresponding status curve – whether it is the Watch, Alert or Emergency Electricity Risk Curve. Normal status is when storage is above the Watch Curve.

### 2.4.1 Normal Status

20. Normal Status is the default and is when current actual hydro storage sits above all the ERCs. The System Operator performs its usual security of supply reporting which includes monthly ESO updates and a weekly security of supply report (which includes updates of available hydro storage and the electricity risk meter status).

### 2.4.2 Watch Status

21. Watch Status is declared when actual hydro storage falls below the Watch Curve<sup>11</sup>. From Watch Status onwards, the System Operator is required to increase the frequency of its security of supply updates (such as the actual hydro storage) from weekly to each business day and as part

<sup>11</sup> To ensure Watch Status is always triggered ahead of Alert, the Watch curve can be increased above the 1% risk curve. This increase above the Alert curve is by at least 200 GWh, or by a worst-case simulated storage drop, whichever is greater.

of this update also provide an estimated “time to” Alert Status and OCC initiation.<sup>12</sup> The System Operator will endeavour to also increase the frequency of ESOs from monthly to fortnightly.

### 2.4.3 Alert Status

- Alert Status is declared when actual hydro storage falls below the Alert Curve. The Alert Curve is also the Alert Contingent Storage Release Boundary, which is the trigger for access to the “Alert” contingent hydro storage.<sup>13</sup>

### 2.4.4 Official Conservation Campaign (OCC)

- An Official Conservation Campaign (OCC) is initiated when actual hydro storage crosses the Emergency Curve and is forecast to remain below it for 1 week or more. Though alternative dates for commencing an OCC may be agreed with the Electricity Authority. The OCC ends when current hydro storage increases above the OCC stop curve<sup>14</sup>, or as determined with the Electricity Authority.

### 2.4.5 Emergency Status

- Emergency Status is only declared once an OCC is called.

### 2.4.6 Risk Meter

- The Risk Meter is a dynamic reflection of the current Electricity Risk Status.<sup>15</sup> The Risk Meter shows where current total storage is within these status bands and indicates how close the next status is to being triggered (Figure 3).

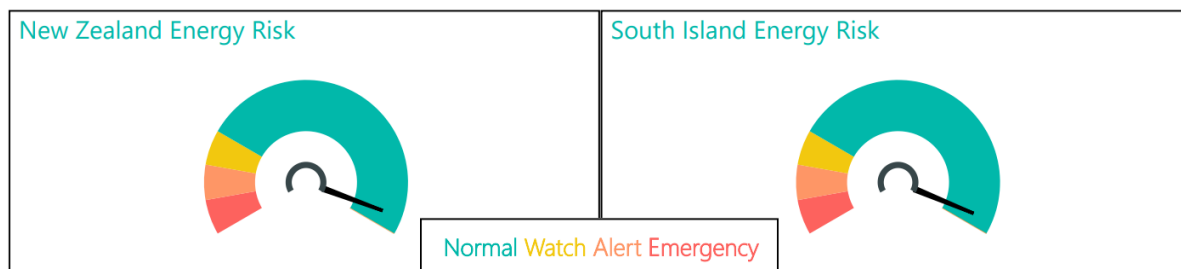


Figure 3. Risk Meter in Normal Status.

<sup>12</sup> This “time to” estimate is discussed further in section 9.4 *Time-to SST used to determine ‘time to’ metrics*.

<sup>13</sup> See section 3.1.4 *Access to contingent hydro storage*.

<sup>14</sup> Section 3.3.4 *Determining the Watch, Alert and Emergency Electricity Risk Curves* provides details on the OCC stop curve.

<sup>15</sup> The Electricity Risk Status as shown on the meter as defined in the [SOSFIP](#).

## 3 Features of the ESO

26. This section provides an overview of the ESO and defines some of its key elements. The figure below is copied from above as it will be referred to throughout this section.

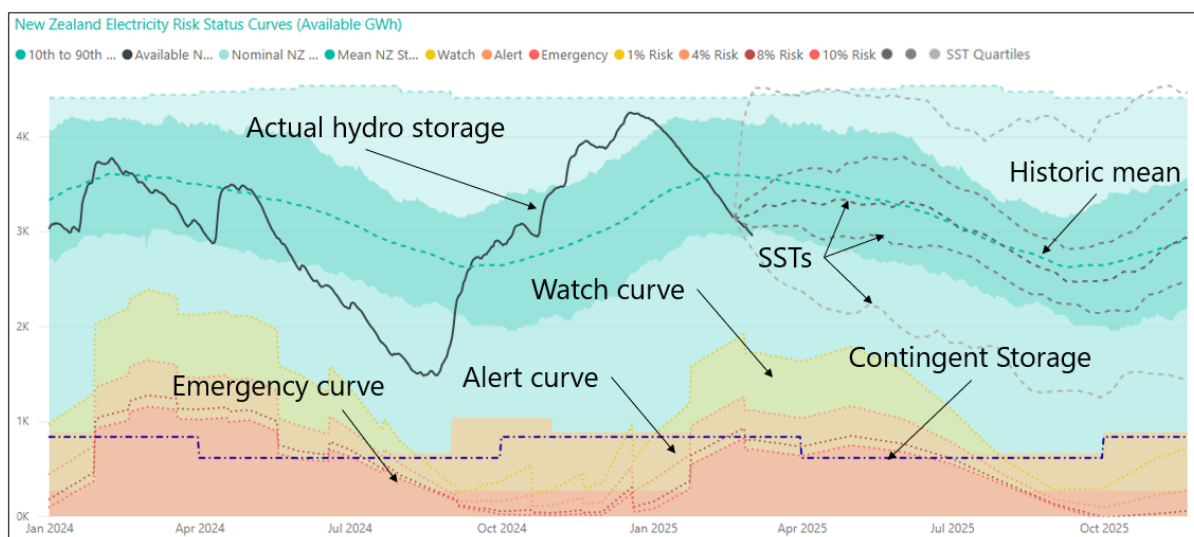


Figure 4. New Zealand ERCs and SSTs (percentiles) example (GWh).

### 3.1 Hydro Storage

#### 3.1.1 Available hydro storage

27. For security of supply purposes, available hydro storage means hydro storage that, in the System Operator's reasonable opinion, is controllable and available for generation of electricity, including contingent storage. We measure the amount of available hydro storage as the amount of electrical energy that can be generated from it (in GWh, on the y-axis in Figure 4).
28. The SOSFIP defines available hydro storage as comprised of hydro storage in lakes:
- Te Anau, Hawea, Pukaki, Manapouri, Tekapo, and Taupo for New Zealand/national; and
  - Te Anau, Hawea, Pukaki, Manapouri and Tekapo for South Island.

#### 3.1.2 Current and historic storage

29. Actual available hydro storage is represented as a solid black line, as shown in Figure 4. It is represented as GWh of electricity that can be generated from the available storage. Historic mean available hydro storage is represented by the dashed teal line, and the surrounding shaded region represents the 10<sup>th</sup> to 90<sup>th</sup> percentile.

#### 3.1.3 Contingent hydro storage

30. Available hydro storage includes contingent hydro storage in lakes (Hawea, Pukaki and Tekapo). Access to contingent storage for generation is, under resource consents, only available during emergency situations. The total contingent storage level is shown by the purple dotted line in Figure.

### 3.1.4 Access to contingent hydro storage

31. Contingent storage can be accessed during an Alert Status or an Emergency Status, depending on the resource consent conditions for the particular lake with contingent storage. There is an Alert Release Boundary and an Emergency Release Boundary, which coincide with the Alert and Emergency Curves respectively (Table 1). If actual national or South Island hydro storage crosses the Alert (or Emergency) curve, access to the Alert (or Emergency) contingent storage is triggered and available for generation.

*Table 1: Contingent Storage lakes with access requirements.*

Lake	Amount of Contingent Storage (GWh)	Condition for Access to Contingent Storage
Hawea	67	Alert Release Boundary
Tekapo	220	Alert Release Boundary (from 1 October to 31 March, otherwise it can be used as controlled storage)
Pukaki	331	Alert Release Boundary
	214	Emergency Release Boundary

## 3.2 Simulated Storage Trajectories (SSTs)

### 3.2.1 Simulated Storage Trajectories

32. The SSTs are a forward projection of a range of possible hydro storage outcomes based on historic inflow sequences. They are developed using a model based on market-like conditions. The SSTs provide a range of future storage trajectories, using multiple different historic inflow records (annual inflow sequences back to 1931). In Figure 4 the SSTs are summarised using the maximum, minimum, mean, upper quartile and lower quartile trajectories.

### 3.2.2 Time-to SST

33. The 'time-to' SST is a hypothetical (or hybrid) inflow sequence created using the lowest (worst case) aggregate inflows on record for each week of the year for the next four weeks, thereafter progressively less pessimistic values are used further into the future.<sup>16</sup>
34. The time-to SST is used when we are in a status requiring heightened security of supply reporting. For example, we use this time-to SST to work out the estimated time to Alert Status and OCC initiation,<sup>17</sup> from when we are in Watch Status onwards. We also monitor it if we see an emerging risk of actual hydro storage crossing the Alert Curve.

<sup>16</sup> See section 9 for further detail.

<sup>17</sup> The System Operator is required to supply a "Time to" metric stating the time to Alert Status and OCC initiation when the available hydro storage crosses the Watch Curve, as set out in clause 4.1 (b) of the [Emergency Management Policy](#).

## 3.3 Electricity Risk Curves (ERCs)

### 3.3.1 Watch, Alert and Emergency Electricity Risk Curves

35. The Watch, Alert, and Emergency Electricity Risk Curves dictate the risk status. When actual hydro storage crosses a status curve, the corresponding risk status is declared. This then signals the actions to be taken by the System Operator and industry participants to address security of supply risks. The status curves are the yellow, orange and red envelopes of shaded area in Figure 4.
36. The status ERCs are set at the higher of two or more metrics:
  - Watch curve: the 1% ERC or the greater of 200 GWh (Watch adder) or the worst-case simulated storage drop above the Alert curve
  - Alert curve: the 4% ERC and the 'floor' which is the minimum available storage level that can set the Alert curve
  - Emergency curve: the 10% ERC and the 'floor' which is the minimum available storage level that can set the Emergency curve.

### 3.3.2 Percentage Electricity Risk Curves

37. The Percentage ERCs are the ERCs calculated in the modelling process. They represent the storage level at which there is a certain risk (in percentage terms) of running out of available hydro storage. For example, if actual hydro storage reaches the 1% ERC, the model is signalling a 1% risk of available hydro storage dropping to zero within the next twelve months.
38. The modelling that determines the Percentages ERCs uses standard modelling assumptions as required by the SOSFIP, or disclosed to us by generators and other electricity industry participants. The model is based on historic inflows data, and a critical assumption is that all other fuels available for generation are used before controlled hydro storage, in order to conserve hydro storage as much as possible. More information on the assumptions is provided later in this document, and the Percentage ERC modelling approach is detailed in section 4 *Calculating the ERCs*.
39. The SOSFIP specifies that the Watch status curve is the 1% ERC, the Alert curve is the 4% ERC, and Emergency status is linked to the 10% ERC and whether an OCC has commenced. These ERCs also consider the corresponding floor values.

### 3.3.3 Floor and Buffer Values

40. Figure 5 below shows that the 1%, 4% and 10% risk curves (the yellow, orange and red dashed lines) drop very low during some of the year – at this time there is low risk of hydro shortage. Typically this is during spring when healthy inflows arrive, including in the form of snow melt. The risk curves are so low, that they are less than the amount of contingent storage.

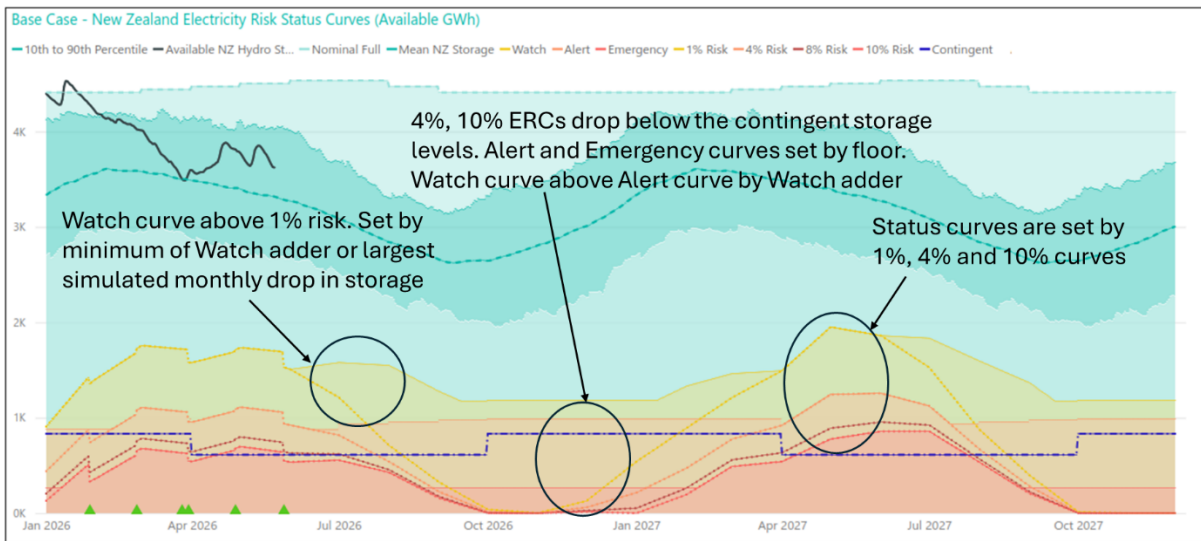


Figure 5. Status curves shown being set by risk curves, or floors.

41. For contingent storage to be accessed for generation Alert Status or Emergency Status needs to have first been declared, and the corresponding Contingent Storage Release Boundary (CSRB) needs to have been crossed. Floors are used to set minimum hydro storage levels for the Alert and Emergency curves (and the CSRBs), to ensure the contingent storage can be accessed when needed.
42. The floors were introduced to prevent situations where the calculated 4% or 10% ERC is less than the total contingent storage available. Without the floor, contingent storage would be unavailable when the percent risk curve is below the contingent storage level – because Alert or Emergency status would not have been declared. Hence, for example, the Alert curve (and Alert CSRB) becomes equal to the larger of the 4% risk curve, or the Alert floor, as shown in Figure 5.
43. The floor is equal to the amount of contingent storage accessible by crossing a Release Boundary, plus the value of any contingent storage associated with lower boundaries, plus a buffer. The contingent storage and default buffer values used to determine the floors are shown below (**Error! Reference source not found.**).
44. A buffer is applied to allow for operational constraints at Lake Tekapo and Waiau and to account for scenarios where the modelled risks did not adequately reflect increased operational risks. The default monthly buffer for the Alert curve is specified in the table below.

Table 2: Floor Values for Contingent Storage Release Boundaries.

Month	Alert Buffer (GWh)	Alert Curve floor (GWh)	Emergency Buffer (GWh)	Emergency Curve floor (GWh)
Jan	153	832+153	50	214+50
Feb	153	832+153	50	214+50
Mar	153	832+153	50	214+50
Apr	153	612+153	50	214+50
May	173	612+173	50	214+50
Jun	263	612+263	50	214+50

Jul	323	612+323	50	214+50
Aug	343	612+343	50	214+50
Sep	363	612+363	50	214+50
Oct	153	832+153	50	214+50
Nov	153	832+153	50	214+50
Dec	153	832+153	50	214+50

45. The SOSFIP allows the System Operator the discretion to determine a different buffer and make it publicly available. Section 3.4 below explains how the System Operator applies this CSRB buffer discretion.
46. If actual hydro storage crosses the Alert ERC (either national or South Island), contingent storage is accessible for generation in all the lakes that have Alert contingent storage. The System Operator's CSRB discretion does not allow for the System Operator to target contingent storage access to individual lakes, or to different lakes at different times.

### 3.3.4 Determining the Watch, Alert and Emergency Electricity Risk Curves

47. The Watch curve is equal to the higher of the 1% ERC or the greater of 200 GWh (Watch adder) or the worst-case simulated storage drop above the Alert curve.
48. When available hydro storage falls below the Watch curve (but is above the Alert curve) it triggers the Watch Status. The Watch Status identifies actions to be performed by the System Operator (Section 2.4.2 *Watch Status*).
49. The Alert curve is equal to the larger of; the 4% ERC, or the relevant floor. If actual aggregate hydro storage crosses the Alert curve it triggers the Alert Status. The Alert curve is also equal to the Alert Release Boundary triggering access to Alert contingent hydro storage. It is possible to move straight to Alert level where the Alert Curve is set by the floor which could exceed the Watch curve (1% risk). In this case all activities associated with the Watch curve will be undertaken if crossing of the Alert curve is expected, and are continued into Alert Status.

The Emergency curve is equal to the higher of; the 10% ERC or the relevant floor. It is also the "Emergency Release Boundary" so signals access to the "Emergency" contingent hydro storage. If available storage is expected to remain below the Emergency curve for more than 7 days, the System Operator can trigger an Official Conservation Campaign (OCC) and declare Emergency Status.

Additionally, the end of an OCC is triggered when hydro storage passes the 'OCC stop curve'. This is set by the 8% risk curve, and is inclusive of storage exceeding the emergency contingent storage release boundary.<sup>18</sup>

## 3.4 Adjusting the CSRB Buffer value

50. As mentioned above, the SOSFIP gives the System Operator discretion to determine a different CSRB buffer if circumstances require it. This discretion provides flexibility to respond to the

<sup>18</sup> See clause 9.23A of the code.

unique operational circumstances/limitations at the time.<sup>19</sup> These situations always evolve differently. Our criteria for using the discretion is that we see:

- immediate risk to security of supply; and
- limited time for a market response to mitigate the risk, and
- bringing forward access to contingent storage can mitigate the risk.

51. Box 1 below explains how we continually monitor for a need to apply the CSRB buffer discretion.

#### Box 1: Ongoing monitoring for a need to apply the CSRB buffer discretion

- Monitor aggregate hydro storage: If aggregate hydro storage is below historic mean for the time of year we assess, and update at least weekly, the estimated 'time to' using the time-to SST to reach the current national and/or South Island Alert risk curve. If the 'time to' is less than 3 months then we initiate the CSRB buffer discretion process on the basis there is an emerging energy risk.
- Monitor individual lake risks: If aggregate hydro storage is below historic mean for the time of year, each week we also assess the 'time to' reach the boundary of contingent storage in each lake with contingent storage. If a lake could (on the basis of its contribution to the time-to SST) reach its contingent storage boundary before aggregate storage would cross the Alert curve, we apply our CSRB buffer discretion process to assess whether it would create a capacity risk.
- Engage with generators to understand operational limitations: To ensure we understand the operational limitations of each generation scheme as a low inflow sequence evolves, we engage with the generators to ensure the information we hold is up-to-date. While we proactively ask for any new information to inform each update of the ERCs, we also ask that generators keep us informed should circumstances change at any time.

52. Figure 6 below provides an overview of the steps and timelines for the CSRB buffer discretion process.

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<sup>19</sup> For example, in late winter 2024, we exercised the discretion in deciding to temporarily increase the CSRB buffer. This was to mitigate the risk the power system may not have been able to meet peak demand during a cold snap should both the Clutha and Waitaki schemes have reached the boundary of contingent storage without being able to access it. Our analysis based on industry input concluded this emerging capacity risk was a potentially viable outcome in spring should unequal drawdown on different hydro catchments continue. In the end, a combination of market response and inflows arriving resulted in contingent storage not being used. But it was accessible if it had been needed in any of lakes Hawea, Pūkaki and Tekapo.

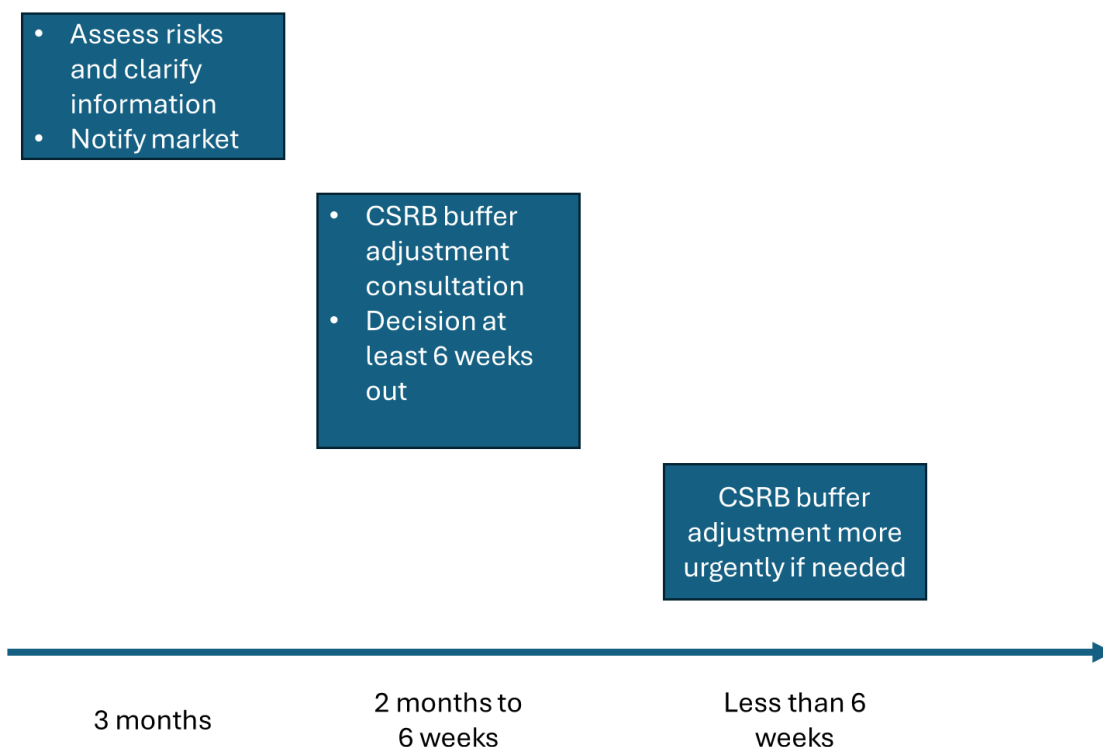


Figure 6. Overview of the CSR buffer discretion process.

53. Box 2 explains the steps in more detail. This is the process we will use to for energy and capacity security of supply risks that are emerging over time. The process balances the need for greater certainty around the ability to contingent storage with the need to adapt the approach to changing conditions.

### Box 2: CSR buffer discretion process

#### STEP 1: ASSESS ENERGY RISK AND CAPACITY RISK (3 months ahead)

- Assess whether there is an immediate energy risk: An energy risk is realised if the power system is unable to fully meet consumer energy demands (i.e. there is insufficient fuel in the system). We consider there is an immediate energy risk emerging if the time-to SST indicates there is the potential for unserved energy within the next 3 months.
- Assess whether there is an immediate capacity risk: We also consider the ability of the power system to meet peak demand with the impacted generation scheme(s) peaking capability restricted due to minimum flow requirements under resource consents (capacity risk). A capacity risk is realised if the power system is unable to fully meet consumer demands for electricity at a particular time (typically during a morning or evening peak during cold, still weather conditions). If one or more individual catchment is forecast to cross its contingent storage boundary within the next 3 months, and the operational implications for the affected generation scheme(s) would put at risk the system's capacity to supply peak demand in a cold snap, we will conclude there is an immediate capacity risk emerging.
- Trigger the process to consult on a draft CSR buffer discretion decision: If there is an energy or capacity risk emerging within the next 3 months we trigger the next step in the process, which is to consult on the use of the CSR buffer discretion. During this process we:

- Check our assumptions and information are correct: Information on fuel, capacity and operational issues is confirmed with participants. We also seek information on the potential for market response options that may yet be available to participants.
- Inform industry and other stakeholders: We inform industry and other stakeholders (including via the System Operator's industry forum) of the potential risks and need for a heightened response from the market.
- Complete analysis and prepare a draft decision for consultation: In parallel with checking our assumptions and seeking information from participants, we complete our analysis of the security of supply risk, and the potential for use of the CSRB buffer discretion to mitigate it. We make a draft decision about the quantum and timing for different buffer(s) to be in effect.

**STEP 2: COMPLETE URGENT CONSULTATION ON RAISING CSRB BUFFER(S) (2 months ahead minimum)**

Consult on the draft CSRB buffer decision: Consultation will run for 1 week. Following consideration of feedback we will review our decision, make a final assessment against our criteria for applying the discretion, and prepare a final decision paper setting out our response to feedback and the rationale for our final decision.

**STEP 3: COMMUNICATE DECISION (6 weeks ahead minimum)**

Communicate the final CSRB buffer decision: Our final decision on whether to use the CSRB discretion is published. If we have decided to use the discretion, our decision will set out the quantum, and timing for the different CSRB buffer(s) to be in effect.

54. Capacity risks to security of supply can also develop more quickly in response to a fast-moving event such as material asset failure(s). Box 3 sets out the approach we will apply should a scenario of this type require a much quicker decision to be made.

**Box 3: CSRB buffer discretion process – fast-moving event**

**COMMUNICATE DECISION (any time)**

Application of discretion with no consultation: Capacity risks and potentially some energy risks can also emerge much more quickly due to unplanned generation outages or fuel supply interruptions. Our ongoing focus on monitoring levels and inflows in each controlled hydro storage lake individually is part of making sure early warning signs of a developing capacity risk are picked up in time for participants to mitigate it through a market response. However, if at any time a security of supply risk emerges rapidly and there is not enough time to complete the full process we will move more quickly. This would result in an immediate decision to that the criteria have been met.

# 4 Calculating the ERCs

## 4.1 This section provides an overview of the methodology used to derive the ERCs

55. The ERCs are calculated using a hydro-thermal scheduling model to simulate operation of the current power system day-by-day and a range of input assumptions regarding the next 12-24 months, as shown by Figure 7. The model uses each historic calendar-year inflow sequence since 1931 to estimate a range of future storage level possibilities. The model is based on the underlying assumption that the market is acting to conserve hydro storage in an emergency.<sup>20</sup> That is, by securing alternative fuels that are available, cancelling outages where possible and thus, conserving hydro storage as much as the system enables.
56. Potential future storage is calculated for each historic inflow sequence since 1931, to create a range of possible future storage scenarios. These future storage values are then used to determine the ERCs. The 1% ERC is the point at which 1% of the future storage projections would run out of hydro storage within the next 12 months. The 10% ERC represents when 10% would run out. [Here is a series of videos](#) which provides a simplified visualisation of the calculation.

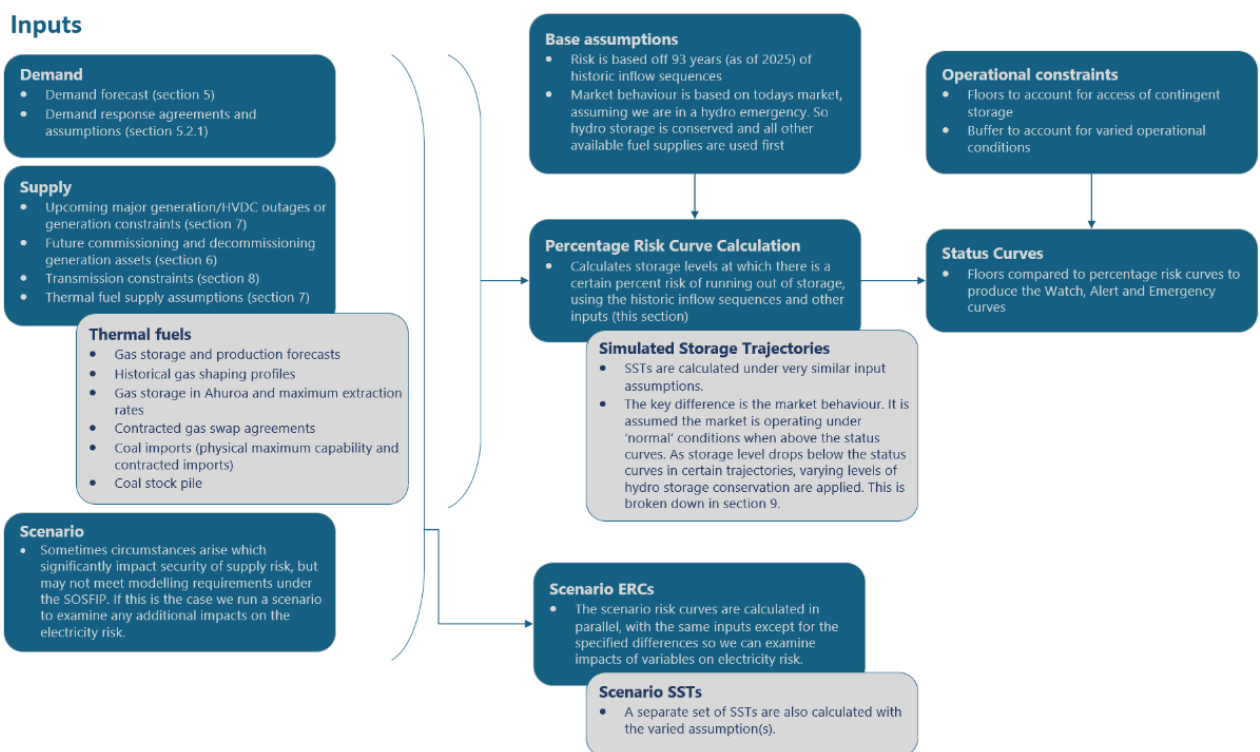


Figure 7. ERC and SST modelling process overview.

<sup>20</sup> See clause 6.1 (b) of the SOSFIP: "The electricity risk curves must assume short-term market behaviour that seeks to minimise the use of hydro storage". These assumptions are primarily used to reflect the expected situation in an emergency (extended period of very low inflows).

## 4.2 Inputs and assumptions

57. The risk curves are based on a set of inputs and assumptions some of which reflect information disclosed confidentially to the System Operator,<sup>21</sup> or confidential within proprietary modelling tools. The underlying assumption is that the market is acting to conserve hydro storage as much as possible and this is reflected in the assumptions behind certain inputs:
- available output from other generation types (section 6 *Generation Assumptions in the Electricity Risk Curves*);
  - demand response (section 5.2 *Demand response in the ERCs*);
  - planned major outages (section 7 *Generator Outages in the Electricity Risk Curves*);
58. The assumptions are intended to be plausible in an extended period of low inflows, and provide a stable benchmark to assess risk when available storage levels are low. They may be less representative when controlled storage is at, or above, average. For example, we assume thermal plant will operate at the maximum available output, with consideration of available thermal fuel and non-deferrable outages. Thermal plant is not expected to be operating this severely during times of high hydro storage, which means that these assumptions are less realistic when actual hydro storage levels are high.
59. The ERCs work with the SSTs to project how likely it is that hydro storage will fall into a level signalling a heightened risk of running out of storage. For example, when modelling the SSTs, the model assumes the market operates normally as storage approaches the Watch curve. It is only once an SST crosses the Watch curve, that the model begins to conserve hydro storage. The SSTs enable us to interpret the likelihood of entering certain risk levels, based on where we are now. For more information about SST modelling and assumptions refer to section 9 *Methodology and Assumptions used to derive the Simulated Storage Trajectories*.
60. We update the ERCs and SSTs each month (more frequently if required, such as when the actual storage level drops below the Watch curve) and modify certain assumptions when new information becomes available.
61. The ERCs can vary largely from the previous update depending on which assumptions are changed. It is important to remember when assessing the impacts of changes that the risk for each month is calculated by modelling out for one year from that month. Therefore, an input that is scheduled to change in the future will impact ERC values ahead of this change.

## 4.3 ERC calculation methodology

### 4.3.1 Estimating future storage

62. Considering the model inputs and assumptions, a set of future storage trajectories is estimated for each historic inflow sequence. As a high-level example, consider calculating a change in hydro storage over an arbitrary amount of time:
1. begin with start hydro storage level in GWh
  2. subtract off the demand in GWh

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<sup>21</sup> The Code and the SOSFIP together requires participants to make all information that can reasonably be expected to impact the ERCs inputs and assumptions available to the System Operator free of charge as soon as reasonably practicable after the participant is aware of it.

3. add on the generation in GWh from other generation types (considering generation and transmission capacity)
  4. add on the inflows in GWh
  5. this will result in a storage estimate for the end of the time-period in GWh
63. The waterfall chart below (Figure 8) shows how this could result in increasing storage (with a substantial amount of non-hydro generation and inflows) and decreasing storage. For ERCs, this exercise is repeated at a weekly interval for up to two years, for each historic inflow sequence, to produce 93 (as of 2025) storage trajectories to consider.

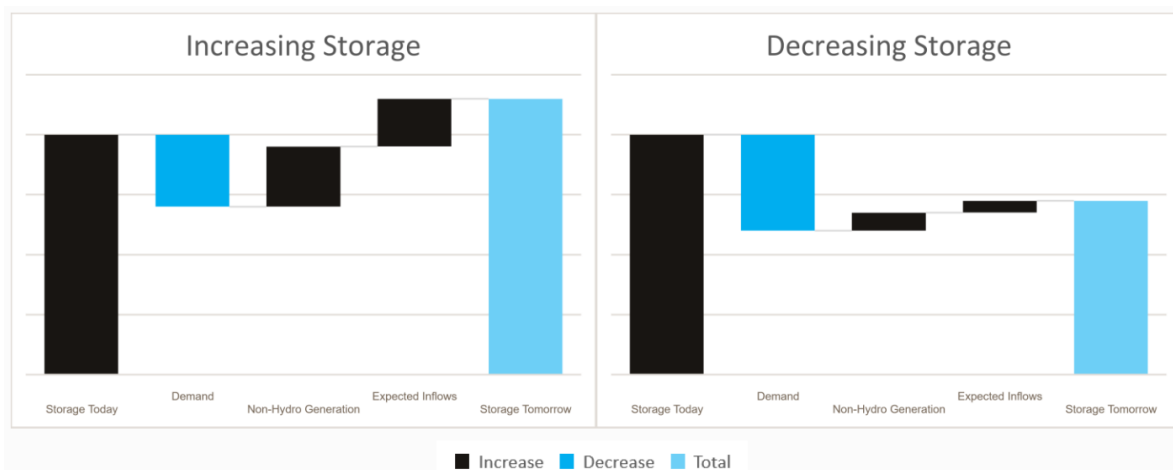


Figure 8. Future storage calculation

64. The above example helps demonstrate at a high level how future storage can be modelled. In reality the ERC modelling procedure is complex because it must consider the whole of New Zealand’s power system.

### 4.3.2 Modelling future storage

65. For the ERCs we use a nodal, price based, hydro-thermal scheduling model to simulate the ability to meet electricity demand over the next 24-36 months. The model takes into account inputs such as fuel restrictions, generation and transmission capacity, outages and market behaviour.
66. The ERCs are based on estimated future storage trajectories, modelled by simulating market conditions in an extended dry period. Under these conditions market behaviour acts to minimise the use of hydro generation to conserve available hydro storage. This is reflected in the market through high water values and high spot market prices. This market behaviour is reflected as a requirement of the SOSFIP<sup>22</sup> when calculating the ERCs.
67. To ensure the physical capability of assets is not exceeded, the model includes generation and transmission constraints and outages. There are assumptions made on the “flexibility” of outages when we get into low hydro periods. This aligns with the system working to conserve hydro generation (and potentially delay or cancel major outages if possible).<sup>23</sup>
68. Minimising hydro generation requires other generators to increase output to meet the system demand. Most of New Zealand’s other generation sources are non-controllable (e.g. run-of-

<sup>22</sup> Clause 6.1 (b) of the [Security of Supply Forecasting and Information Policy](#): “The electricity risk curves must assume short-term market behaviour that seeks to minimise the use of hydro storage”.

<sup>23</sup> See section 7 *Generator Outages in the Electricity Risk Curves* for outage assumptions.

river hydro, wind, solar, co-generation) or operate at constant levels such as geothermals.<sup>24</sup> Thermal generation is controllable and is maximised under the simulated market behaviour to minimise use of available controlled hydro storage. Thermal generation can, however, be limited by fuel restrictions and the ERC modelling applies thermal derating to thermal generators to reflect fuel constraints.<sup>25</sup>

69. A range of historic inflow sequences (dating back to 1931) are used as a proxy for potential future inflows. The model simulates the trajectory of available hydro storage under the input assumptions, for each inflow sequence, to produce a range of storage outcomes. These storage trajectories, not to be confused with Simulated Storage Trajectories,<sup>26</sup> are the output from the model of the power system, which models a full 12 months.

### 4.3.3 Calculating the percent risk

70. Once we have our range of future storage trajectories, we proceed to determine our risk of running out of storage. Typically, available storage is managed so that we are above the risk curves and hence there is less than 1% risk of storage dropping to zero (running out) within the next 12 months. This means that none of the storage trajectories run out of hydro storage within the next 12 months based on our current actual storage.
71. To first simplify, consider we have 10 historic inflow sequences which are 12 months long. We put these inflows into the ERC model with a start storage equivalent to our current actual storage, and the model incorporates the assumptions around market behaviour and capabilities. The model will output 10 year-long estimates of future storage trajectories based on each inflow sequence, at a weekly granularity, as shown in Figure 9.
72. From these trajectories we can see that if we subtract (1) from (2) we get a start storage position from which one trajectory would reach 0 GWh of hydro storage over the next 12 months. The difference (3) between (1) and (2) now becomes the storage level in GWh, that we would need to be at, to have a certain percent risk of running out of hydro storage. In this simplified version, (3) would set the 10% ERC value for that month, as 1 out of 10 sequences reaches 0 GWh.

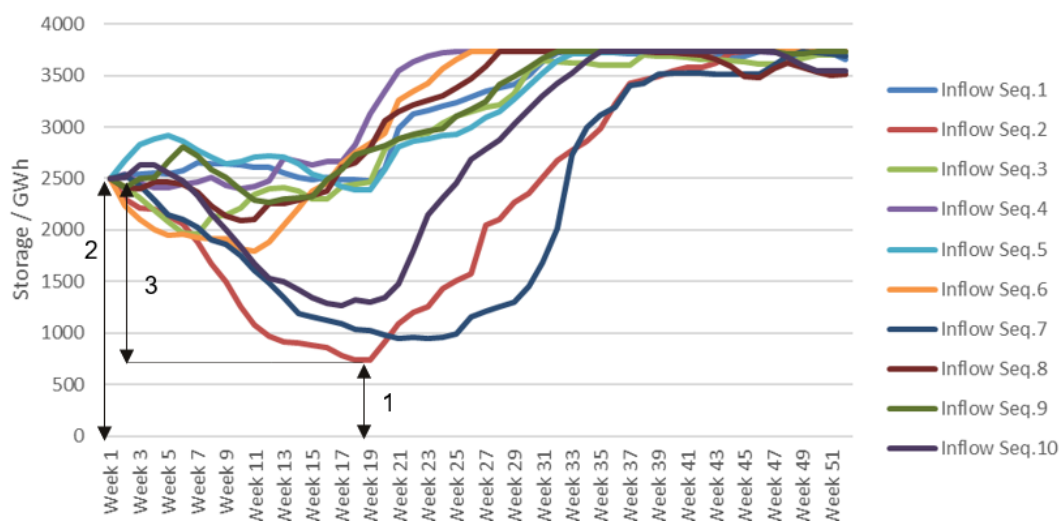


Figure 9. Example 10% percent risk curve calculation.

<sup>24</sup> See section 6 *Generation Assumptions in the Electricity Risk Curves* for generation type specific assumptions.

<sup>25</sup> This is discussed further in section 6.2.1 *Thermal fuel validation methodology*

<sup>26</sup> See section 9 *Methodology and Assumptions used to derive the Simulated Storage Trajectories* for SSTs.

73. When calculating the percent risk for ERCs we have a much larger number of sequences to consider, allowing us to calculate a variety of risk levels more accurately. For ERCs, we need to determine the storage levels at which there is a 1%, 4%, 8% and 10% risk of running out of hydro storage within the next 12 months. These risks levels are defined by the SOSFIP and set the status curves.

#### 4.3.4 Putting it together to get a risk curve

74. The above example centres around determining the storage level at a singular point in time, for which there is a risk of running out of storage at any point within the next 12 months. We calculated the week 1 storage level, where 10% of the inflows ran out of hydro storage at any point in the next 12 months – which happened to be week 18. This gives us one point for the 10% risk curve.
75. The risk of running out of hydro storage changes depending on the time of year, largely due to inflows. For instance, we can draw hydro storage down lower towards spring because historically there is a high chance of getting good inflows to sustain us through the next 12 months. A similar storage level in March may present a higher risk, as through winter we historically get less inflows and have a higher demand forecast.
76. Thus, to create a curve, we need to repeat the above process for multiple points in time. For ERCs, we calculate a point each month, for the next 12-24 months. A depiction of calculating a point on the 1% and 10% risk curves is shown in Figure 10 below. The highlighted trajectories drop below zero GWh storage at some stage over the next 12 months. The start storage level at which 1% of the trajectories cross sets a point for the 1% curve (yellow). We can then see that by lowering the start storage, we can do so until 10% of the trajectories cross, to set a point on the 10% curve (red).
77. The model is run for each month, to determine the storage levels at which there is a 1%, 4%, 8% and 10% risk of running out of hydro storage within 12 months from that run month. The points are then interpolated between months (see the dashed lines) to make up the corresponding percent risk curve. We recommend watching [this video](#) to help visualise the process.

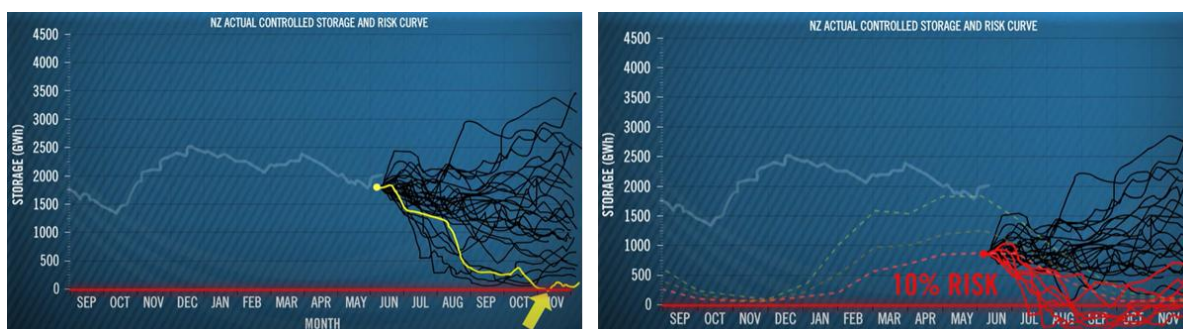


Figure 10. Percent risk curves.

## 5 Demand Forecast in the Electricity Risk Curves

78. The ERCs model the future relationship between supply and demand. The ERC sequences are modelled up to 24 months into the future, so we require a forecast of demand for the next 3 years.

### 5.1 Demand Forecast Inputs and Assumptions

79. The forecast used in the ERC modelling is based on an expected forecast (P50). At a high-level, demand accounts for assumed network losses, embedded generation and incorporates assumptions regarding demand growth. Key inputs include:
- Gross Domestic Product,
  - opening or closing industrial connections, and
  - historic demand trends.
80. The weekly average demand values (GWh) for each month are input into the ERC model, and can be found in the [ERC Assumptions Spreadsheet](#).

### 5.2 Demand response in the ERCs

81. The calculation of the ERCs includes consideration of demand response. In an emergency situation it is likely the market price signals will influence a voluntary reduction in demand from the base forecast. When we assess the amount of demand response to assume, we consider:
- the impact of distributed energy resources,
  - information regarding formal demand response contracts,
  - historical observations, and
  - future demand response availability.
82. Currently, the analysis results in a baseline demand response reduction of 2.5% of the demand forecast. However, this fluctuates typically based on the availability of different options under the Meridian-NZAS Tiwai demand response agreement.<sup>27</sup> For example, in 2024 the 'Option 4' demand response was exercised, after which there is a standdown period where the largest demand response options are unavailable. This meant that our assumed demand response available in the calculation of the 2025 risk curves went down, but up again at the end of the standdown period.

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<sup>27</sup> See the [agreement](#) for further information.

### 5.3 Impact of Demand Forecast on the ERCs

- 83. Our demand forecast is provided by Energy Link and is reviewed quarterly and updated if necessary. However, in some situations (such as during 2020 when the closing of Tiwai was signalled for 2021) we update the forecast on an ad-hoc basis.
- 84. At the simplest level increasing forecast demand increases forecast risk levels and decreasing forecast demand drops the risk levels. A higher demand forecast will mean a greater demand on generation, and more dependency on hydro storage and generation for managing security of supply events.
- 85. The relationship is not linear – i.e. X GWh of demand decrease in a month does not drop the curves by X GWh in that month. The curves are calculated over a 12-month period and are determined by the lowest point of storage. Therefore, the curves will change up or down by the accumulated demand change each month, between the calculation month and the time of lowest storage. This will be different for each month of the year. Hence the risk changes over the year.
- 86. An example of demand change affecting risk is shown below (Figure 11). Due to the inclusion of a lower demand forecast in the ERC update in February 2025, there was a significant drop in the ERCs.

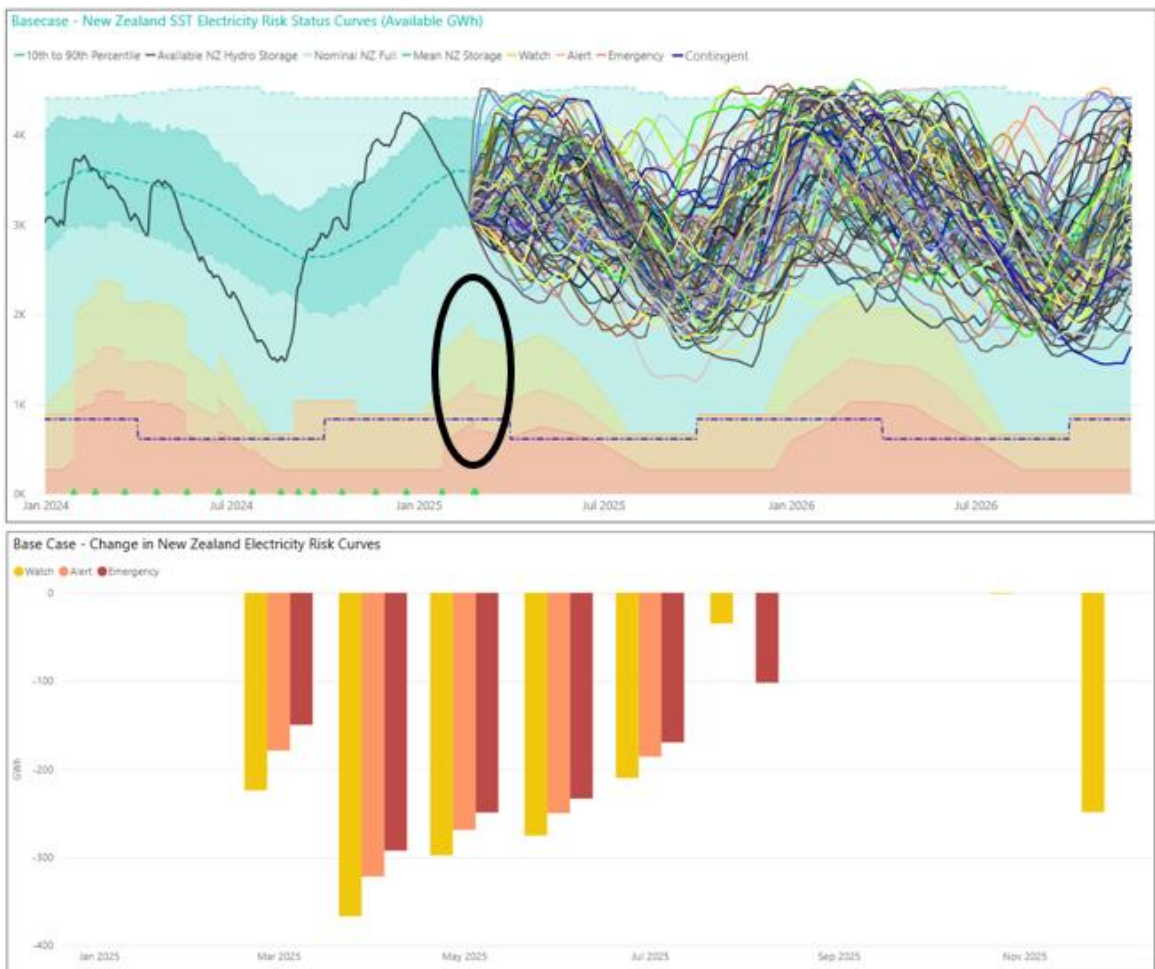


Figure 11. Reduced demand forecast reducing the ERCs.

# 6 Generation Assumptions in the Electricity Risk Curves

## 6.1 Supply Assumptions used for Generation

87. This chapter provides an overview of how varying generation behaviour of different generation types is reflected in the ERCs. Thermal fuel assumptions are a major part of the ERC model. Behaviour of thermal generators modelled in the ERCs is defined by the SOSFIP clause 6.1(b) *"[The electricity risk curves must] assume short-term market behaviour that seeks to minimise use of hydro storage"*. This clause is incorporated into the model as an assumption that generation from thermal resources will always be prioritised over hydro generation, at its available capacity.
88. Actual market operation does not align with this assumption all the time. Under conditions with increased or average hydro the available hydro generation is not minimised. However, under extended periods of low hydrology, hydro generators want to conserve available hydro storage (corresponding to an increase in the value of available stored hydro). This results in increased market prices, incentivising the generation fleet to reduce hydro generation and mitigate chances of a hydro shortage. The greater the risk of a hydro shortfall (due to extended dry periods), the more the market behaviour would converge to the assumptions underpinning the ERCs, i.e. would operate to minimise the use of available hydro storage.
89. Other assumptions around generation behaviour for sources such as geothermal, wind and hydro are also made, and account for their variation in generation capability throughout the year. These behaviours are included in the ERC model as generation profiles and are classified as either; "profiled output" or "based on historical sequence". The behaviour profiles for each generator are shown in the [Electricity Risk Curve Assumptions Spreadsheet](#). This table also includes additional information on future plant that will be commissioned in the next 2-3 years and resultantly included in ERC supply assumptions, and any de-ratings of plants due to notified restrictions in their generation capacity.

## 6.2 Thermal Generation Output

90. ERCs are derived assuming generation assets are not subject to constraints on the availability of thermal fuel, including delivery constraints, unless reasonably reliable information is known that indicates otherwise ([SOSFIP](#), clause 6).
91. When preparing ERCs we check if there is enough thermal fuel - accounting for known constraints – to meet the expected quantity of available thermal generation. To operate the thermal generation at rates assumed in the ERC model (i.e. under extended dry periods) requires more thermal fuel than that under typical market conditions. To ensure the model adequately reflects limitations thermal fuel supply may have on thermal generation, we use the following thermal fuel validation method.

### 6.2.1 Thermal fuel validation methodology

92. In the thermal fuel validation methodology we assess the thermal fuel:

- Supply chain capacity, for the likes of natural gas production and coal import rates.
  - Availability, including stored thermal fuels and ability to arbitrage from other users.
93. We use a combination of historical production and consumption values, and information provided by relevant participants, when collecting data and evaluating assumptions. We base our assumptions off the physical capability of thermal fuel availability. In a dry year emergency, with high market prices, we assume that there is sufficient incentive to procure fuel at the maximum limit – so this is what is used in ERCs. If there is still insufficient thermal fuel available, the maximum available capacity of thermal generation will be derated in the ERC model. This process is as follows:
- I. As a standing assumption, we limit generation from the Whirinaki diesel station to 60 GWh over a six-month period<sup>28</sup>.
  - II. ERC storage trajectories assume that thermal generation will operate at its maximum capacity (subject to outages) to conserve water.
  - III. We convert this thermal generation to fuel consumed per month. We assume that the Huntly Rankine units will run, in the first instance, on coal. This determines the quantity of thermal fuel (gas and coal) required to meet the thermal generation capability available.
  - IV. We compare fuel consumption for thermal generation to expected gas and coal supplies, accounting for:
    - a. Gas or coal demand that is capable of being made available for electricity generation (e.g. potential industrial gas reallocation)
    - b. Gas or coal demand that is unlikely to be made available for electricity generation (e.g. residential gas use)
    - c. Gas and coal storage inventories (e.g. coal stockpile and gas storage levels)
    - d. Gas and coal inventory drawdown replenishment rates (e.g. maximum gas extraction rates and maximum coal import capability)
  - V. After all this, if gas and coal supply is insufficient to meet the demand required by the available thermal generation capability, we derate the maximum available capacity of thermal generation assumed for the ERCs, so that it is consistent with estimated available gas and coal availabilities.
94. The assumptions that are used in this process are estimated using the best possible information available, so change regularly over time as new information becomes available. Under normal circumstances we aim to gather the necessary information monthly. Unless there is good reason to do otherwise, we will only assess thermal fuel constraints in the short term, consistent with the availability of robust thermal fuel supply information.
95. Some of the detailed information used in the above verification steps is confidential due to its commercially sensitive nature, which means we cannot disclose the specific assumptions we have used. The [ERC assumptions spreadsheet](#) is produced with each ERC update, and includes a table of approximate generation from coal and gas in the ERC analysis.

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<sup>28</sup> Contact Energy state this is an estimate based on current modelling. Contact makes no representations about the accuracy of this information or takes any responsibility for any inaccuracies.

## 6.3 Profiled Output – Geothermal and Run of River Hydro

96. Generators that are identified as using a “profiled output” are modelled using predefined generation patterns based on historic output. The profiles change over the year due to historic patterns in operation. For example, some geothermal generators have months where their generation output is typically higher or lower, and therefore their generation profiles vary from month to month. These profiles are comprised of 4 values: week-day; week-night; weekend day; and weekend night.
97. Historic output is typically averaged over the last 5 years, but we apply discretion in our modelling in some cases to account for irregularities such as major outages. Typically, geothermal and some run-of-river hydro generators are profiled as they follow predictable patterns in their annual generation. In the case of the hydro generators we model as profiled, we have insufficient plant and inflow information to model based on historical inflow sequences.

## 6.4 Based on Historical Sequences – Hydro, Wind and Solar

98. Unlike the somewhat predictable generators (geothermal generation for example), the generation patterns for hydro generators can vary each year depending on their levels of storage and inflow patterns. Larger hydro generators that have sufficiently reliable historic inflow datasets are modelled using historic inflow sequences as a basis for generation output. Weekly inflow datasets are created for Clutha, Manapouri, Waitaki, Tekapo, Waikato, Cobb, Coleridge and Waikaremoana, based on all inflow sequences since 1931.
99. Generally, each of the modelled generators supply energy based on these historical inflow datasets, in addition to the amount of storage available. This is a complex calculation as generators store or use water to ensure a balance between avoiding spill and avoiding shortage. The generation quantities are determined using proprietary software provided by [Energy Link](#). The average monthly generation profiles that were calculated using this method for the March 2024 ERC update are shown below (Figure 12).

	Hydro Generation							
	Waitaki	Clutha	Manapouri	Waikato	Tekapo	Coleridge	Waikaremoana	
Mar-24	578	336	295	283	56	22	47	
Apr-24	492	361	410	302	66	23	53	
May-24	574	366	489	366	83	26	61	
Jun-24	698	333	507	446	90	28	73	
Jul-24	588	306	524	587	115	27	85	
Aug-24	528	321	500	570	102	27	85	
Sep-24	467	352	503	451	84	29	69	
Oct-24	442	417	543	357	71	32	60	
Nov-24	511	489	561	454	111	32	48	
Dec-24	394	462	475	274	104	31	38	
Jan-25	532	460	457	275	119	28	36	
Feb-25	762	406	432	308	125	25	42	

Figure 12. Reduced demand forecast reducing the ERCs.

100. Wind and solar have become more prominent sources of generation, so are now also modelled off historic sequences where data is available. Historic wind and solar data is obtained from Renewables.ninja<sup>29</sup> and starts in 1982, so includes 40 annual sequences. For years prior to this,

<sup>29</sup> [Renewables.ninja](#) provides several years of weather data in various locations around the globe.

we use a flat profile estimate based on a capacity factor, which is appropriate as the ERCs consider average energy generation over time.

## 6.5 Impact of Generation Assumptions on the ERCs

101. As discussed above, when the availability of thermal generation exceeds the available gas supply, de-ratings are applied to the available thermal plant. The higher the de-ratings the more the ERCs increase as more hydro generation is required to meet demand when thermal generation is restricted.
102. Adding a new generator that can provide a reasonable amount of energy to the market will decrease the risk of an energy shortfall and therefore reduce the ERCs as more generation becomes available to meet demand. Similarly, when a generator increases their capacity and the energy it can provide the ERCs decrease. But with any decommissionings or capacity reductions (and therefore energy) the ERCs will increase, as again more controllable hydro generation is required to balance the demand.

# 7 Generator Outages in the Electricity Risk Curves

## 7.1 Outages Included in the ERCs

104. In the previous chapter, we discussed how behaviour of different generation types is incorporated in the ERC modelling. We also need to consider when these generators will not be operating due to outages. Only specific generator outages are included in the ERC model, and this chapter will discuss how we choose which outages to include and why.
105. In each monthly ERC update, we look at the generation outages over the next year that have been listed on the Planned Outage Coordination Process (POCP) website<sup>30</sup>. We then select the outages we wish to include according to a set of criteria. The outages included in the modelling are updated and published in the ERCs assumptions spreadsheet.<sup>31</sup>

## 7.2 Base Criteria

106. First, we consider outages that could not be deferred in an emergency situation. As the ERCs are a model of market behaviour in an emergency situation, we assume there is sufficient incentive to defer any outages that are able to be moved. This ensures any possible generation fleet is available to conserve hydro storage use.
107. Second, we typically only consider outages which begin in the next 8 months. This window allows us to capture any confirmed major outages that could impact security of supply. We automatically include any outages within the next two months—we assume that it is unlikely outages within two months will be cancelled due to logistical and scheduling reasons. For outages further out we only include large outages (more than 30 MW, and for longer than 7 days) and we check with generators whether these outages would be deferrable in the event of a hydro shortage.
108. Finally, we only include outages that will result in a loss of energy. Therefore, for hydro stations we only include outages that are likely to lead to the spill of water and lost energy. This is because the ERCs are a measure of the energy available in the system rather than capacity. They are a reference against which actual stored energy (in the form of available storage) can be compared, and thus we only include outages that will increase hydro generation and thus storage consumption. For example, if one unit of a four-unit hydro generator is on outage, it is unlikely to have any impact on the amount of hydro generation used. The ERC model already assumes a low level of hydro generation, so taking that unit out will likely not make a difference. In the rare case it is required, then taking it out will typically mean hydro generation from elsewhere is used, meaning the total amount of hydro generation used is the same regardless. If we suspect the outage to result in spill, we enquire with the relevant participants to confirm if this is a possible outcome of an outage.

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<sup>30</sup> See [Planned Outage Coordination Process](#) (POCP) website

<sup>31</sup> See [ERCs assumptions spreadsheet](#)

## 7.3 Generation Type Specific Outage Criteria

109. Once we have extracted the list of outages from POCP, we select which ones to include according to the criteria described above. These criteria are interpreted differently for each fuel type.

### 7.3.1 Thermal and Geothermal

110. All thermal and geothermal outages are included according to the above criteria (section 7.2). When these generators are on outage, more hydro storage will need to be consumed to cover for the loss of generation.

### 7.3.2 Wind

111. In addition to the above criteria (section 7.2), wind farm outages are only included if there is a loss of more than 50% of capacity. Wind farms typically rotate the use of their turbines to allow for maintenance, and this is included in the capacity factor we use for that specific wind farm. Any outage that is under this threshold will typically not impact the modelled capacity as it will already have been accounted for. For example, a 40% capacity factor for a specific wind farm will include allowances for small single turbine outages.

### 7.3.3 Run-of-River Hydro

112. All run-of-river hydro outages meeting the above criteria (section 7.2) are included in the ERC model. Run-of-river hydro generators do not have controlled storage. Thus, when there is an outage, any water is being spilt and not used to generate, so this is a source of potential generation loss. This means that more controlled storage from stored hydro generators must be used to replace this generation.

### 7.3.4 Controlled Hydro

113. As described above, when there is an outage of a controlled hydro generator, the amount of hydro generation used in the model is usually unaffected. The only time when we count controlled hydro outages is when the outage will result in spill and lost energy. In this case, potential generation in the form of stored hydro is being lost, and this outage would be included in the ERC model.

### 7.3.5 Cogeneration

114. All existing cogeneration and respective outages are accounted for in the model using a profiled output.

### 7.3.6 Solar

115. There is an increasing number of grid scale solar installations. If the above criteria are met (section 7.2), outage factors will be applied to solar generation in the model, based on the percentage of the solar farm on outage.

### 7.3.7 HVDC

116. We also include major planned HVDC outages, which are shown in the ERCs assumptions spreadsheet. An HVDC outage will restrict the transfer between the North and South Island. Most of the controlled hydro storage in New Zealand is in the South Island, and most of the thermal generation in the North Island. In the case when hydro storage is low, HVDC transfer will be predominantly in the south direction, with North Island generation supporting South Island demand. An outage of the HVDC could restrict the ability of North Island generation to provide for South Island demand, meaning that more South Island generation will need to be used, resulting in increased hydro storage consumption.

## 7.4 Impact of Outages on the ERCs

117. Outage assumptions are one of the reasons for business-as-usual changes to the shape of the ERCs. Each outage included in the ERCs can have a different impact on the shape of the curves, depending on the size and duration of the outage. Generally, if plant is removed from the model due to being on outage, the ERCs will increase. Sometimes previously modelled outages will be cancelled, deferred or modified, resulting in a decrease in the ERCs. Each outage is slightly different, and sometimes other assumptions are updated each month at the same time, so it can be difficult to determine the impact of individual outages on the ERCs.

# 8 Transmission Assumptions in the Electricity Risk Curves

## 8.1 Transmission Security Constraints

- 118. Transmission lines throughout New Zealand have limits to the electricity they can transmit. These limits can change depending on the time of year having variable impacts on the capacity of the national transmission network. The derivation of the ERCs includes a nodal model of the New Zealand power system, so we include specific transmission line constraints where they could constrain generation.
- 119. An example of where transmission constraints may impact the ERCs, is where a large amount of thermal generation is brought online to conserve hydro storage. There may be enough fuel for them all to run at full output, however we also need to consider the transmission capacities out of the region. Depending on the circumstances, thermal may not be able to generate at full capacity if doing so could overload lines or compromise security standards on the power system. We include a small number of key constraints in our modelling where they have the potential to constrain generation, particularly in a dry year.

## 8.2 Transmission Constraints in ERCs

### 8.2.1 AC Constraints

- 120. Table 3 outlines the constraint equations we include in our ERC modelling. An example of how to interpret the equation constraints is as follows. The power flow on the circuits BPE\_PRM\_HAY1.1 multiplied by a factor of 1, in addition to the other terms in the Wellington Stability equation, must not exceed 1127MW. These equations are based on an engineering assessment of transmission capability, including stability constraints. For more information see the System Security Forecast.<sup>32</sup>

*Table 3: Security constraints included in ERC modelling.*

Constraint	Constraint Equation	Transfer Limit
Wellington Stability	$1*BPE\_PRM\_HAY1.1 + 1*BPE\_PRM\_HAY2.1$ $+ -1*HAY\_WIL\_LTN1.1 + -1*HAY\_WIL\_LTN2.1$ $+ -1*MGM\_WDV1.1$	1127
Upper South Island Stability	$-1*ASB\_TIM\_TWZ2.3 + -1*ISL\_TKB.1$ $+ 1*LIV\_NWD1.1 + -1*ASB\_TIM\_TWZ1.3$	1330
Southland Stability	$-1*INV\_ROX1.1 + -1*INV\_ROX2.1$	1000

<sup>32</sup> See [System Security Forecast](#) (SSF)

Constraint	Constraint Equation	Transfer Limit
	+ 1*NMA_GOR_TMH1.1 + 1*NMA_GOR_TMH2.1 + 1*EDN_INV.1	

## 8.2.2 HVDC Constraints

121. We account for limits in HVDC transfer by modelling maximum transfer in both the north and south direction (Table 4). Also included are any upcoming HVDC outages.

*Table 4: HVDC Transfer Limits.*

HVDC	Limit (MW)
North Flow (BEN_HAY)	1100
South Flow (HAY_BEN)	700

122. Typically, North Island generation will be relied upon to support South Island demand in a dry year. This is because most of the generation in the South Island is controlled hydro, so in a situation where there is very low hydro storage, hydro generation would be restricted. For North Island generation to support South Island load, the HVDC must be utilised to transfer this electricity.

## 8.3 Impact of Transmission Assumptions on the ERCs

123. Generally, the AC network constraints do not have a large impact on the ERCs, hence we only include a few specific constraints. While limits on the AC network may constrain generation on or off during peak periods or in certain situations, over long periods of time the AC network generally allows a free flow of electricity. The system operator also maintains a watchlist of asset owner outages that can adversely impact security of supply by constraining on hydro generation and/or constraining off non-hydro generation. This is used to inform conversations with asset owners about rescheduling outages that negatively impact security of supply, particularly in a dry spell.
124. The HVDC link between the North and South islands can substantially impact the ERCs. Most of the hydro generation is in the South Island, and most of the thermal generation is in the North Island, so the capacity of the HVDC link is crucial to modelling the ERCs, and in fact the main reason we model South Island risk on its own. HVDC capacity, like generation capacity, if increased will lower the ERCs and vice versa. Similarly, outages on the HVDC link will increase the ERCs.

# 9 Methodology and Assumptions used to derive the Simulated Storage Trajectories

## 9.1 Overview of the SSTs

125. This chapter will provide an overview of the methodology used to derive the SSTs. The SSTs are presented with the ERCs as part of the monthly ESO and provide a forward-looking assessment of possible future storage scenarios. We update SSTs every month at the same time as ERCs, and also increase the frequency of updates as required when security of supply risk increases.
126. The aim of SSTs is to provide a range of future storage scenarios, based on historic inflows and present-day market behaviour, so we can assess the likelihood of hydro storage reaching a risk level. Similarly to the ERCs, the SSTs are calculated using a model built to replicate market behaviour in the current power system. One SST is calculated for each historic inflow sequence, and is an estimate of what future storage could look like over the next 12 months for this inflow sequence, under market conditions which consider current storage levels.

## 9.2 SST Assumptions

### 9.2.1 Differences between SST and ERC assumptions

127. The assumptions which feed into the SSTs are similar to ERCs. However, there are some critical differences. The fundamental reason behind the differences is that the ERCs are designed to reflect an emergency situation, where SSTs model expected market behaviour at all storage levels.
128. When hydro storage reaches a level where there is an increased risk that hydro storage may drop to zero, the market will not operate the same as during circumstances when hydro storage is abundant, and risk is low. These are the levels of storage at which the ERCs sit, and hence means in the ERC model the market behaviour is governed by the assumption that hydro storage is conserved. As such, assumptions which feed into the ERC calculation are crafted to reflect this behaviour, such as by prioritising thermal generation over hydro generation, reducing demand due to voluntary demand response in reaction to price signals, and cancelling outages where possible.
129. This may not reflect actual market behaviour, especially at lower hydro risk levels when there is more available hydro storage. At this stage, we would likely see lower market prices, not incentivising dry-year backup resources (such as thermal and demand response), because they are not needed to conserve hydro storage. In contrast, the purpose of the SSTs is to provide a range of plausible future hydro storage trajectories (based off the same historic inflows), and as such provide an indication of the likelihood of hydro storage dropping to a certain risk level.
130. The following sections will cover how this is reflected through each of the assumptions in the SSTs.

## 9.2.2 Generation

131. The SST model attempts to capture market behaviour more consistent with how it operates relative to storage level. The main generation types affected are hydro and thermal. As a result, the SST model uses variable priced offers, to mimic how the market responds to various levels of storage. For example, in a sequence of high inflows leading to abundant storage, hydro generation is priced low, as we generally observe in reality. When there is a period of low inflows and hydro storage drops, hydro gets priced higher so that thermal generation gets dispatched ahead of hydro.
132. Wind, solar, geothermal, co-generation, etc, have the same behaviour as the ERCs (see Section 6.3 and 6.4).

## 9.2.3 Demand forecast

133. The SSTs are derived using the same demand forecast as the ERCs.<sup>33</sup> However, SSTs use a difference set of assumptions around demand response, where in ERCs a reduction is applied to the demand forecast to reflect voluntary demand reductions in response to high price signals during hydro shortages.
134. As the SSTs aim to model general market conditions, the full demand forecast is used in the calculation when operating in normal status above the 1% ERC/Watch curve, unless any demand response agreements are in action<sup>34</sup>. If storage in an SST drops below the 1% ERC, the same demand reduction as used in ERCs is applied to the forecast demand to account for price responsiveness. If the SST continues downwards and drops below the 10% ERC/Emergency curve, demand is reduced by a further 2% of the base demand forecast to account for the impact of an OCC.

## 9.2.4 Outages

135. All known generation outages are taken from the Planned Outage Coordination Process (POCP)<sup>35</sup> at the start of the update month. All of which are included in the calculation of SSTs to reflect typical market conditions, as opposed to ERCs where they are filtered according to the criteria in Section 7 to determine which outages could be cancelled or deferred in an emergency situation.
136. However, if an SST drops below the 10% ERC/Emergency curve, any planned deferrable outages are excluded, based on the assumption that there will be capability and incentive for generators to defer these outages. The above applies to both planned generation and HVDC outages.
137. No forced generation outage factor is applied.

## 9.3 Interpreting the SSTs

138. Projected storage is calculated for each historic inflow sequence since 1931, to create a range of future storage scenarios. All these storage sequences are plotted with the ERCs in the ESO. They also appear elsewhere such as in the weekly summary represented by mean, min, max, lower quartile and upper quartile curves as in Figure 13. The lower quartile is not one single SST

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<sup>33</sup> ERC demand forecast can be found in the [ERC assumptions spreadsheet](#).

<sup>34</sup> Such as the Tiwai demand response.

<sup>35</sup> See [Planned Outage Coordination Process \(POCP\)](#).

curve based on a historic inflow but is a compound curve calculated on a week-by-week basis, where 25% of the storage trajectories fall below that point in that week. The same is true for the others, i.e. the minimum is when one trajectory falls below that point in that week.

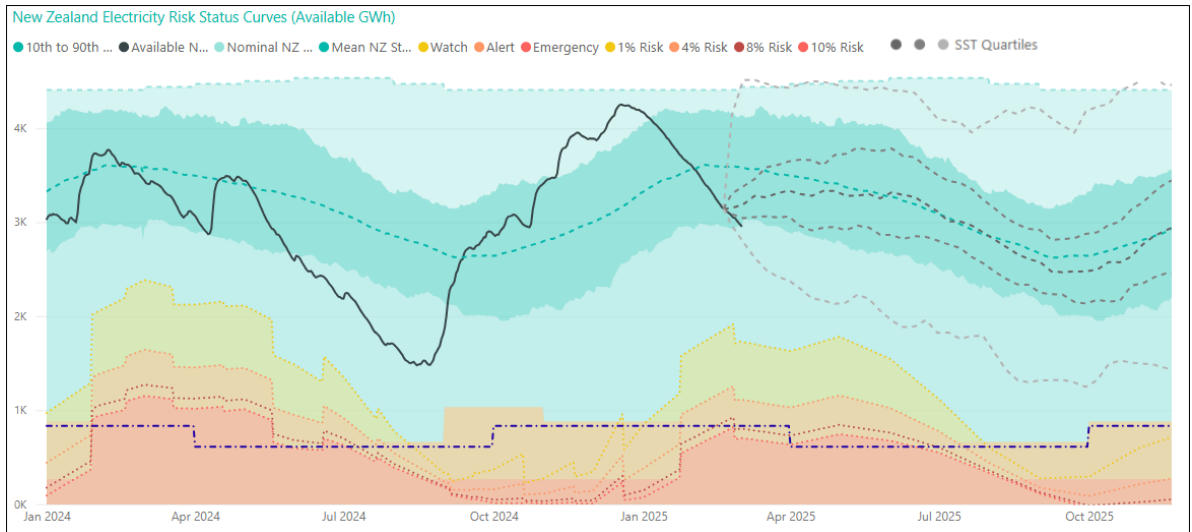


Figure 13. SST ranges as displayed in the weekly summary.

139. A key take out from the SSTs is the number of sequences crossing ERCs and the date these crossings occur. In Figure 14, nine sequences cross the Watch curve while one crosses the Alert curve. This indicates based on current market conditions, an OCC is unlikely to be required in the 12 months from the time SSTs are updated.

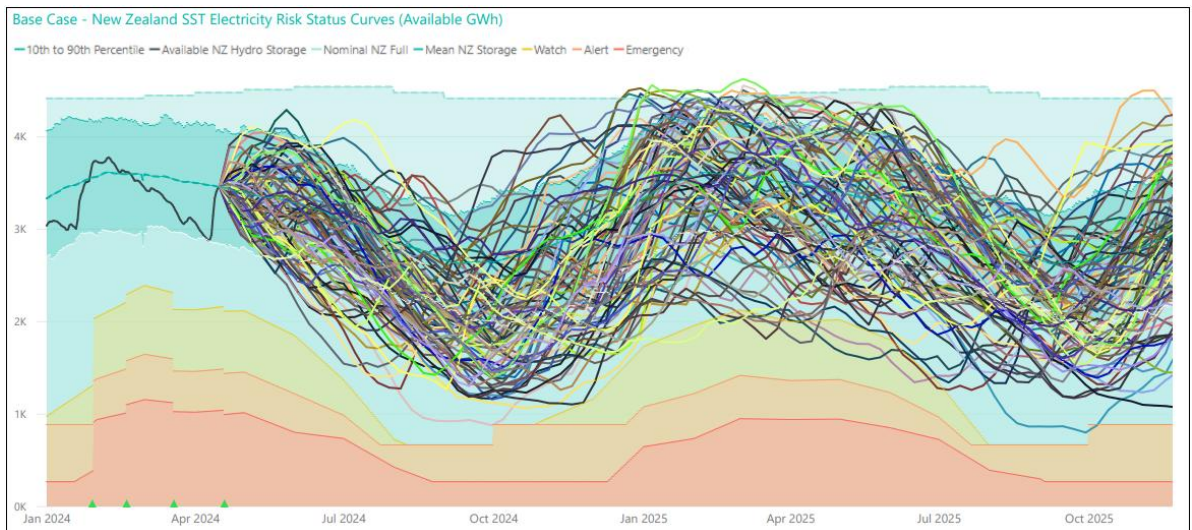


Figure 14. SSTs as displayed in the monthly security outlook update.

## 9.4 Time-to SST used to determine 'time to' metrics

140. A 'time-to' SST is used to determine the 'time to' metrics set out in section 3.2.2 *Time-to SST*. This is created by using:

- Weeks 1 to 4: the lowest weekly inflows
- Weeks 5 to 8: the 3rd lowest weekly inflows

- Weeks 9 to 12: the 5th lowest weekly inflows
  - Weeks 13+: the 10th lowest weekly inflows
141. These inflows are combined into one synthetic inflow sequence. This is the red line in Figure 15. During Watch status this SST and the time to metrics are published as part of the monthly ESO, see Figure 16.

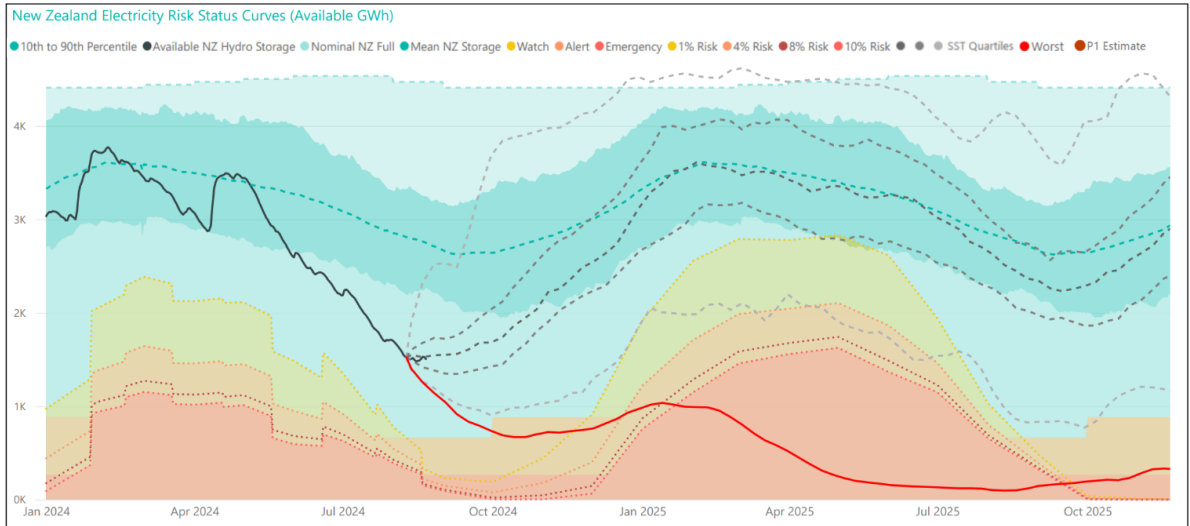


Figure 15: Time-to synthetic SST.

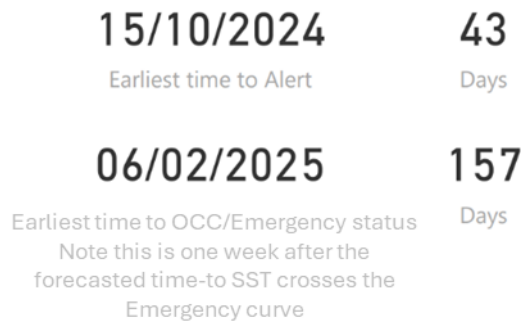


Figure 16: Time to estimates based off the time-to SST.

## 10 Contracted Fuel Case

142. The primary difference between the Contracted Fuel Case and the Base Case is the use of firm thermal fuel contracts rather than assuming additional thermal fuel could be contracted (up to the physical limit estimate as discussed above for the Base Case).
143. Firm contracted thermal fuel quantities (gas, coal and diesel) are collected from market participants monthly.
144. By restricting available energy strictly to currently secured contracts, this case intentionally highlights the physical capacity that remains uncontracted, and the ability for additional

contracting to reduce risks. This reinforces that contracted positions require continuous updating to provide ongoing security of supply cover.

