TRANSPOWER

Electricity Risk Curves 101

Risk curves have been developed for the purpose of reflecting the risk of extended energy shortages in a straightforward way, using a standardised set of assumptions.

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Version History

Version	Date	Change
1.0	15 April 2024	A merged and refined 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.

Contents

1.0 Introduction to the Electricity Risk Curves

1.1 Introduction

This document is aimed at helping participants better understand the Electricity Risk Curves (ERCs), Risk Status, Simulated Storage Trajectories (SSTs), and other elements of the security of supply framework. This first chapter will introduce the ERCs and provide an overview of each feature.

1.2 Overview of the ERCs

The ERCs (Figure 1) are used to show how actual hydro storage, and projected hydro storage is tracking relative to a calculated risk of energy shortage (Percentage ERCs) based off a standard set of assumptions. Figure 1 below shows the Percentage ERCs, Watch/Alert and Emergency ERCs, simulated storage trajectories (SSTs) and historic storage levels. The Watch, Alert and Emergency ERCs are based off different Percentage ERCs and are used to identify activities, such as commencing an Official Conservation Campaign (OCC), to be performed by the System Operator to manage a low hydro situation. Each element of the ERCs is broken down further below (Section 1.3). We produce charts for both New Zealand and the South Island on its own. The ERCs are available on the [Transpower website](#) and are updated monthly to include up-to-date information in the model.

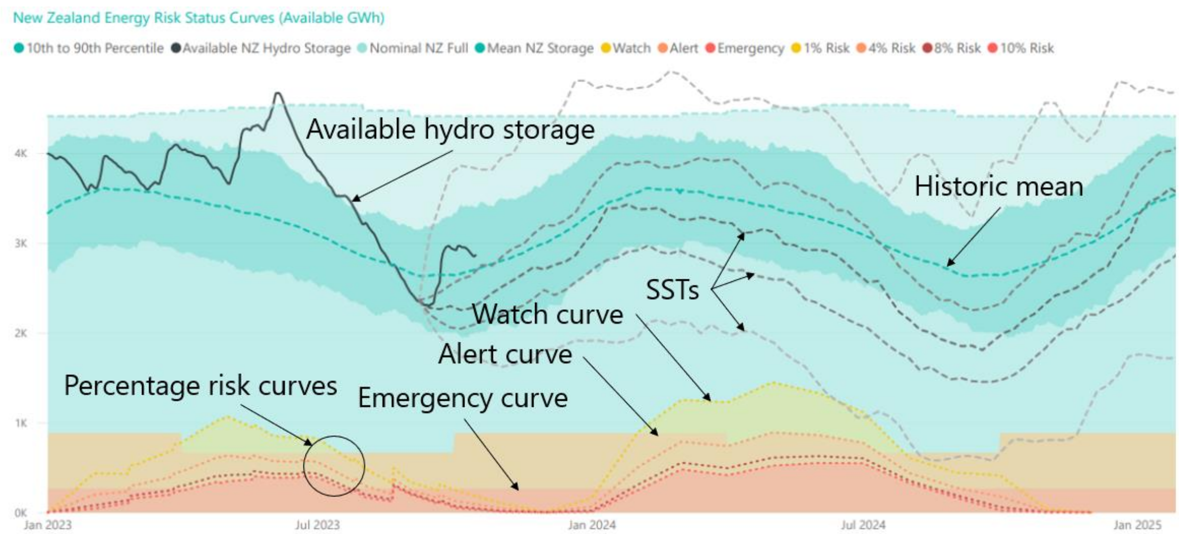

Figure 1. New Zealand Electricity Risk Curve example (GWh).

1.3 Elements of the ERCs

1.3.1 Available hydro storage

Available hydro storage is the volume of water in our hydro lakes that is controllable and can be used for hydro electricity generation. If there is no hydro storage, then electricity supply shortages are likely. Only certain lakes contribute to available storage; Te Anau, Hawea, Pukaki, Manapouri, Tekapo, and Taupo. Further detail is covered in Section 3.1.

The available hydro storage is represented as a solid black line, as shown in Figure 1. Hydro storage is tracked over time, as lake levels rise, the line representing storage moves up the graph and vice-versa. It is measured as GWh of electricity that can be generated from the available storage. Historic mean hydro storage is represented by the dashed line, and the surrounding shaded region represents the 10^{th} to 90^{th} percentile.

Estimated future storage is represented by a range of grey dashed lines – the Simulated Storage Trajectories (SSTs). The SSTs are a forward projection of hydro storage based on historic inflow sequences, using a model that reflects today's market. We display the SSTs based off historic inflow sequences representing the maximum, minimum, mean, upper quartile and lower quartile.

1.3.2 Contingent Storage, Floor and Buffer Values

Contingent storage is hydro storage that is only able to be used for hydro electricity generation if hydro storage falls below a certain level, known as a Contingent Storage Release Boundary. Currently there are two Contingent Storage Release Boundaries for our hydro lakes. Most of the contingent storage becomes available at the Alert Release Boundary and the rest at the Emergency Release Boundary.

The floor and buffer set minimum hydro storage levels for the ERCs based on the necessary contingent and minimum storage.

Together; the contingent storage, floor, and buffer, provide a pragmatic minimum level of hydro storage when the estimated risk of running out of water drops to very low levels in the spring and summer months. For more information, see Section 3.

1.3.3 Percentage Electricity Risk Curves

The Percentage ERCs represent the estimated risk of energy shortage if hydro storage were to fall to that level. For example, if available hydro storage reaches the 1% ERC, this means that there is a 1% risk that hydro storage will drop to zero at some point within twelve months assuming hydro generation is used last. This calculation is based on historic inflow data. For more information on how these Percentage ERCs are modelled, see Section 2.

1.3.4 Watch, Alert and Emergency Electricity Risk Curves

We publish Watch, Alert and Emergency Electricity Risk Curves. These are the lines representing the envelope of the coloured shaded areas in Figure 1 and have the following definitions:

- The Watch Curve is equal to the larger of; the 1% ERC, or the relevant floor and buffer.
- The Alert Curve is equal to the larger of; the 4% ERC, or the relevant floor and buffer.
- The Emergency Curve is equal to the larger of; the 10% ERC or the relevant floor and buffer.

If the hydro storage position reaches the Watch Curve, this indicates there is about a 1% risk that hydro storage will drop to zero at some point within twelve months assuming hydro generation is used last and based on historic inflow data. Available hydro storage falling below the Watch Curve triggers the Watch Risk Meter Status (see Section 1.3.7 The Risk Meter). From the Watch Status onwards, the System Operator is required to increase the frequency of the security of supply updates (such as the available hydro storage) from weekly to each business day and as part of this update also provide an estimated time to Alert Status and OCC initiation. The System Operator will endeavour to also increase the frequency of ERC updates from monthly to fortnightly.

Available hydro storage falling below the Alert Curve triggers the Alert Risk Meter Status and is also the "Alert Release Boundary" so signals access to the "Alert" contingent hydro storage. It also may indicate a 4% risk that hydro storage will drop to zero at some point within twelve months assuming hydro generation is used last and based on historic inflow data. This would be if current storage crosses over a section of the Alert Curve where the 4% risk curve is larger than the floor and buffer (Figure 2).

The Emergency Curve is also the "Emergency Release Boundary" so signals access to the "Emergency" contingent hydro storage. As with above, it may also indicate there is a 10% risk that hydro storage will drop to zero at some point within twelve months assuming hydro generation is used last and based on historic inflow data. If the current available hydro storage is forecast to remain below the Emergency Curve for one week or more, the System Operator is required to commence an OCC or unless otherwise agreed with the Electricity Authority. If an OCC is called, this will then trigger the Emergency Risk Meter Status.

The rest of the time, in "Normal Status", there is less than a 1% risk of hydro storage dropping to zero within 12 months under the same assumptions. This is when current available hydro storage sits above all the ERCs.

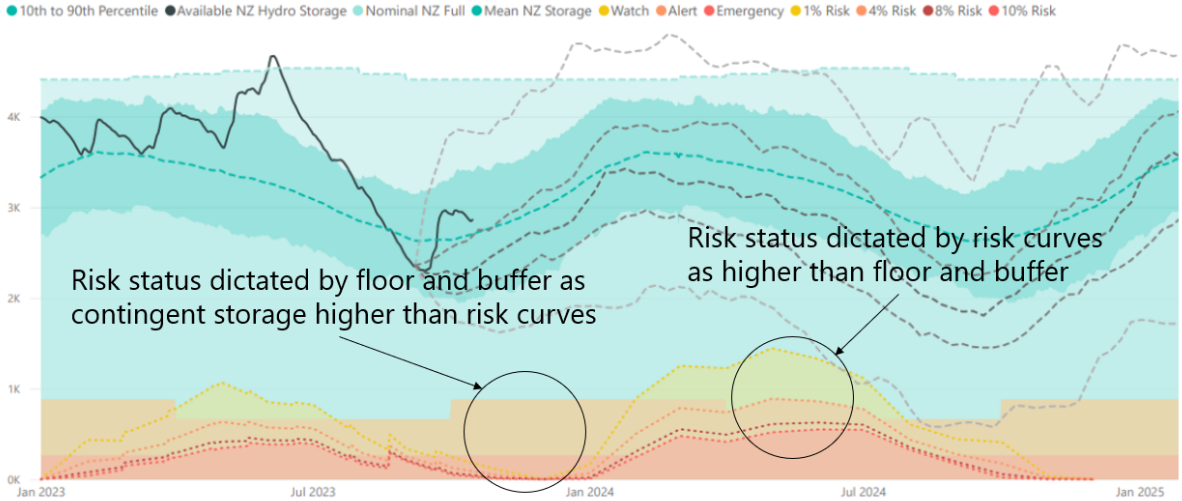

Figure 2. Status curves as determined by risk curves or the floor and buffer.

1.3.5 Official Conservation Campaign (OCC) Triggers

An OCC is initiated when the actual available hydro storage crosses the Emergency Curve and is forecast to remain below it for 1 week or more. The OCC ends when the hydro storage increases back above the 8% ERC with the addition of a buffer. Despite the conditions above, alternative dates for commencing (as well as ending) an OCC may be agreed with the Electricity Authority.

1.3.6 'Time to OCC' Approach

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.

The calculation of the 'Time to' metric uses the following steps:

- A 'worst case inflows' synthetic SST is created using the lowest inflow on record for each week of the year.
- This 'worst case inflows' synthetic SST is then used to work out the estimated time to Alert Status and OCC initiation. So, this would be the minimum time we could expect based on historical inflows.

1.3.7 The Risk Meter

The Risk Meter is a dynamic reflection of the current Electricity Risk Status – as defined by the Status ERCs (Section 1.3.4). 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). The Alert and Watch statuses are triggered when the storage crosses the respective curve. Emergency status is only triggered when an OCC is launched.

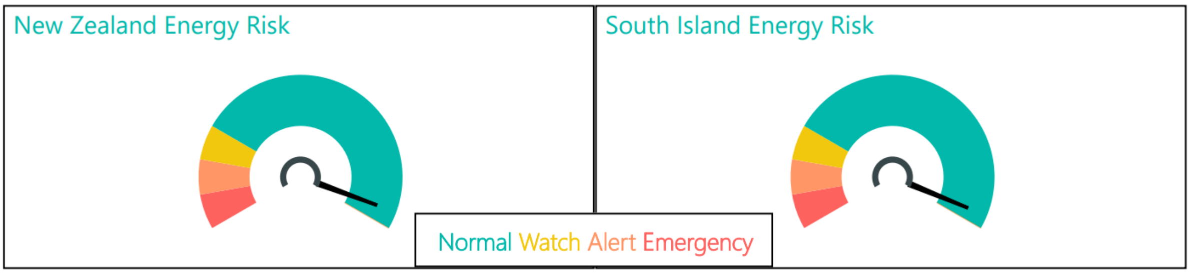

Figure 3. Risk Meter example.

2.0 Methodology used to Derive the Electricity Risk Curves

2.1 Calculating the ERCs

This chapter will provide an overview of the methodology used to derive the ERCs. The ERCs are calculated using a model of the current power system. The model predicts what future storage would look like if the inflows over the next 12 months were identical to historic inflow sequences, and assumes the market was acting to conserve hydro storage by securing more alternative fuel, cancelling outages, and consuming hydro storage last. 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 dictate the risk curves. Essentially, the 1% ERC is the point at which 1% of the future storage projections would run out of hydro storage, the 10% ERC represents when 10% would run out. [Here is a series of videos] which provides a simple visualisation of the calculation.

2.1.1 Estimating Future Hydro Storage

Future storage is calculated using a variety of inputs, including:

- the known physical capability of the power system, i.e. generation and transmission capacity,
- existing hydro storage,
- demand for electricity (including transmission losses),
- historic and current inflows to our storage lakes, and
- assumptions on fuel availability for other types of generation.

For example, storage at the end of tomorrow can be estimated by taking storage today, subtracting demand for tomorrow, then adding expected inflows and non-hydro generation for tomorrow. The waterfall chart below (Figure 4) shows how this works under two scenarios: increasing storage and decreasing storage. This exercise is repeated for each time-period under investigation (for the ERCs this is 1-2 years) and for each historic inflow sequence.

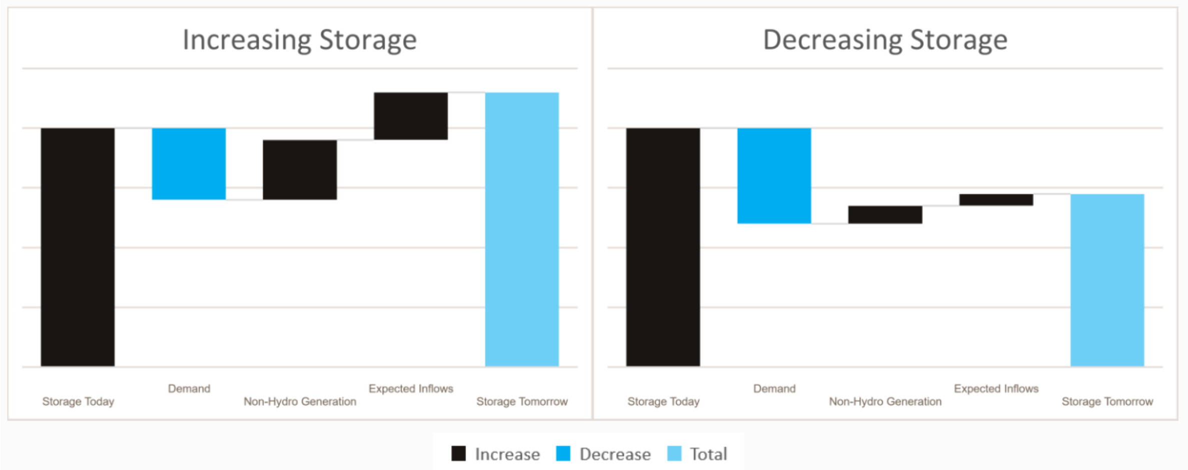

Figure 4. Example storage calculations.

2.1.2 Demand and Non-Hydro Generation

The chart above implies three very important factors which underpin the ERC analysis:

- expected inflows based off historic data,
- amount of demand for electricity, and
- expected amount of non-hydro generation.

The demand for electricity (including network losses) is forecast using a combination of econometrics, incorporating drivers such as GDP growth, short-term trends, and long-term trends.

The expected amount of non-hydro generation is estimated using:

- physical attributes of the system; capacity of plant and estimated capacity factors, including generation that is being decommissioned/commissioned in the study period, and
- behaviour of market participants.

Both are based on assumptions. For physical attributes, historic data is generally used as a good indicator of future attributes, unless further information is known. For example, a generator may notify us of planned expansion of their plant, and we also include an up-to-date log of upcoming commissioning and decommissioning generation assets.

For market behaviour, we adopt the defined standard set out in 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*". These assumptions are primarily used to reflect the expected situation in an emergency (extended period of very low inflows); typically, hydro is not conserved at all times, but in such an emergency it very likely would be. For more information on the generation assumptions, see Section 5.

2.1.3 Example Calculation

Once the future storage scenarios are estimated, we can see if or when the possible future storage scenarios drop to zero, and thus determine the necessary percentage risks of shortage in the future. The image below (Figure 5) shows a simplified version of the calculation, with the storage trajectories of 10 different inflow sequences, rather than all the hydro inflow sequences since 1931.

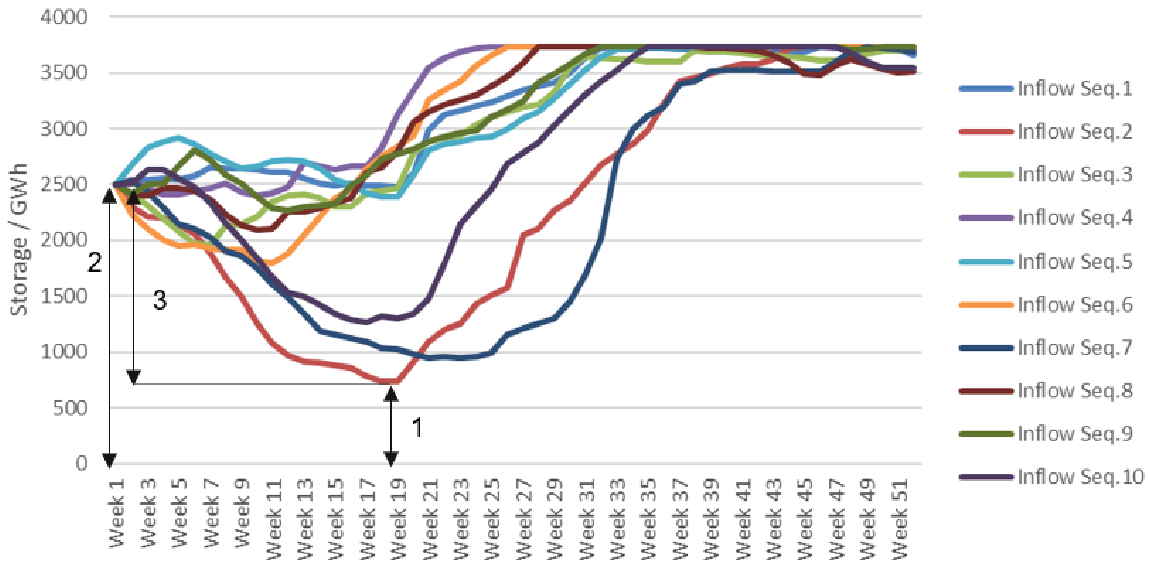

Figure 5. Percentage risk example calculation.

These storage trajectories, not to be confused with Simulated Storage Trajectories, are the output from the model of the power system, which models a full 12 months. 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 and lead to energy shortages. In this simplified version, this would then set the 10% ERC value for that month, as 1 out of 10 sequences reaches 0 GWh. In reality, as well as having a larger number of sequences to deal with, we also use a smoothing function over the data to convert the number of inflow sequences to the percentage risk.

This example represents the process to estimate the risk values for one month. To calculate risk values for each subsequent month over the next 1-2 years, the model runs many times. This video also helps in the visualisation of this process.

2.2 ERC Assumptions

The risk curves are based on a set of assumptions, detailed in the latest ERC Input Assumptions document which is reviewed monthly and updated if necessary. Some of these assumptions are fixed, in particular:

- geothermal, co-generation, wind, and small hydro plant operate to expected levels,
- storable inflows are conserved where possible,
- all thermal plant operates at maximum capability to meet demand (capability includes a small, forced outage percentage),
- forecast expected demand is reduced by 2% to reflect voluntary reductions in demand due to price, and
- historic inflow sequences are used to represent the range of possible future inflow sequences.

These assumptions are used because they are plausible in an extended period of low inflows, and provide a stable benchmark to assess risk when controlled storage levels are low. They may be less representative when controlled storage is at, or above, average. For example, all thermal plant would not be expected to be operating during times of high hydro storage, which means that the ERCs are less realistic when controlled hydro storage levels are high.

We update the ERCs each month (more frequently if required, such as when the controlled storage level drops below the watch curve) and modify certain assumptions when new information becomes available, in particular:

- demand forecast is typically updated each quarter, or ad hoc if required,
- supply assumptions, including assumed capacities for each generator and generation profiles if used,
- thermal fuel limitations, including any additional thermal de-rating due to available gas supply being less than gas needed for generation, and
- planned outages within the next two months or planned outages within the next eight months that cannot be deferred in an emergency situation.

The ERCs can be very different 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.

3.0 Contingent Storage in the Electricity Risk Curves

3.1 Contingent Storage Overview

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. This includes contingent hydro storage whether currently available or not. Sources of available hydro storage in New Zealand are from Lakes Tekapo, Pukaki, Hawea, Manapouri, Te Anau, and Taupo. Each of these lakes have specific requirements for an allowable minimum and maximum lake level, but some of these lakes have special resource consents that allow further use of water for electricity generation when in, or approaching, an emergency situation. This type of storage is referred to as contingent storage. The conditions that allow contingent storage to be used differ with each hydro lake and are governed by resource consents between the relevant local authority and the consent holder (generator).

3.2 Contingent Storage Release Boundaries

Contingent storage release boundaries are triggers for the release of contingent storage. There is an Alert Release Boundary and an Emergency Release Boundary which coincides with the Alert and Emergency Curves respectively (Table 1).

Table 1: Contingent Storage for NZ Lakes.

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

3.3 The Floor and Buffer

A floor and a buffer are included in the Alert and Emergency Electricity Risk Curves and resultantly the Contingent Storage Release Boundaries. They are designed to maintain a value of useable storage when the calculated Percentage ERCs drops very low, and are not additional to the calculated Percentage ERC value. The buffer allows for pragmatic emergency management in low risk, low inflow situations. Currently we are using 50 GWh as the buffer.

The floor was introduced to prevent situations where the calculated 4% or 10% ERC is less than the total contingent storage available. This generally happens in the low-risk summer months. Without the floor, contingent storage could not be accessed when it is needed; when the risk curve is below the contingent storage level. The floor is therefore equal to the amount of contingent storage accessible by crossing a Release Boundary, plus the value of any contingent storage associated with lower boundaries. The current contingent storage values are used to determine the floor and buffer values (Table 2).

Table 2: Current Floor and Buffer Values for Contingent Storage Release Boundaries.

Boundary	Floor + Buffer Value (1st Oct to 31st March)	Floor + Buffer Value (1st April to 30th September)
Alert Release Boundary (Alert Curve)	612 + 50	832 + 50
Emergency Release Boundary (Emergency Curve)	214 + 50	214 + 50

3.4 Impact of Contingent Storage on the ERCs

As discussed above, contingent storage is incorporated into the Alert and Emergency ERCs and as a result these curves are also the Contingent Storage Release Boundaries.

If reported storage were to fall to the Alert Release Boundary, contingent storage access which is linked to the Alert curve would be triggered at this point, but there would be no observable change to the ERC chart. Reported storage would not increase and the ERCs themselves would not change shape due to the triggering of contingent storage.

4.0 Demand Forecast in the Electricity Risk Curves

4.1 Importance of the Demand Forecast in the ERCs

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. This section will explain what is included in the demand forecast.

4.2 Demand Forecast Inputs and Assumptions

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.

The weekly average demand values (GWh) for each month are input into the ERC model, and can be found in the ERC Assumptions Spreadsheet.

4.3 Impact of Demand Forecast on the ERCs

We review our demand forecast quarterly and update it 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.

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.

One thing to note is 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.

An example of demand change affecting risk is shown below in the old ERC format (Figure 6). Due to the inclusion of a lower demand forecast in the ERC update in February 2019, there was a significant drop in the ERCs.

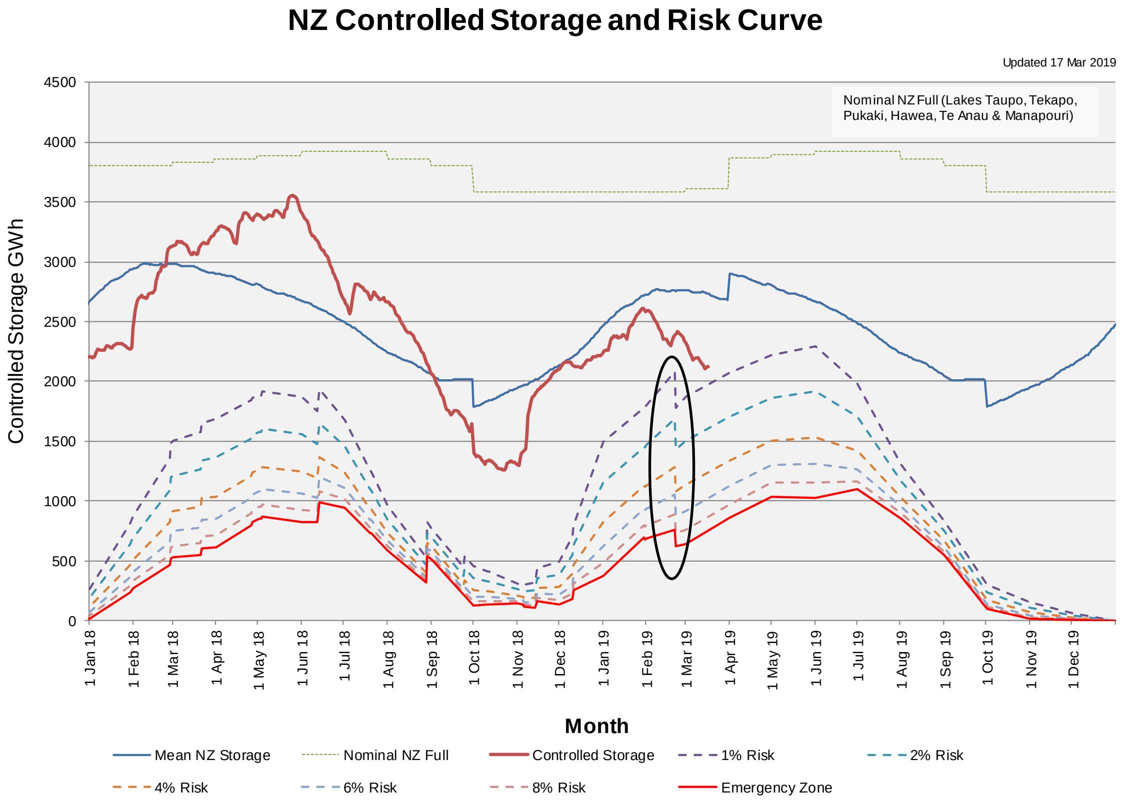

Figure 6. Reduced demand forecast reducing the ERCs.

5.0 Generation Assumptions in the Electricity Risk Curves

5.1 Supply Assumptions used for Generation

This chapter will provide an overview of how varying generation behaviour of different generation types is reflected in the ERCs. The 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. The 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 help reduce chances of a hydro shortage situation. The greater the risk of a hydro shortfall (due to extended dry periods), the more the market operation would converge to the assumptions underpinning the ERCS, i.e. would operate to minimise the use of available hydro storage.

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 any de-ratings of plants due to notified restrictions in their generation capacity.

5.2 Thermal Generation Output

In the ERCs thermal generation is modelled differently to other generation types – it is modelled as though it will always run prioritised over hydro at its available capacity. While this simplicity does have limitations, it appropriately reflects expected market behaviour as hydro storage declines, as discussed above.

To operate the thermal generation at rates assumed in the ERC model (i.e. under extended dry periods), more thermal fuel is required than normal. To ensure the model adequately reflects any limitations thermal fuel supply may have on thermal generation, we assess the thermal fuel:

- supply chain capacity
- availability, including stored thermal fuels and ability to arbitrage from other users.

From these assessments we estimate a maximum amount of thermal fuel that generators could plausibly gain access to, and if needed limit generation to the amount of fuel that can be supplied.

In general we find Coal and Diesel are constrained due to supply chain limitations, rather than fuel availability because they can be imported from liquid international markets.

Gas has no supply chain constraints but can be limited on fuel availability. Because there is no import facility and producers have little flexibility to increase production, if production levels are low, availability can be low. Resultantly, restricting the ability for the market to source more if needed, and the ability for gas generation to operate at high levels for a sustained period of time.

The monthly gas availability forecast is modelled by:

- Forming a gas production forecast
- Adding in availability from gas storage, incorporating a plausible storage draw down rate
- Taking off demand from all sectors, excluding petrochemicals manufacturing and electricity generation
- Taking off assumed demand from the petrochemical sector
- Assuming up to 20TJ/day of gas (per gas demand response) can be reallocated from the petrochemical sector to electricity generators
- Including any formal agreements in place for gas reallocation from other users to electricity generators

The balance is the maximum amount of gas assumed available for generation. If the balance is less than the amount needed to fuel the gas generation, we limit the amount of gas generation to match gas availability in the model.

Some of the detailed information used by these 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 assumed generation from coal and gas.

5.3 Profiled Output – Geothermal and Run of River Hydro

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.

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.

5.4 Based on Historical Sequences – Hydro, Wind and Solar

5.4.1 Hydro Inflow Sequences

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.

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 7).

	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 7. Monthly hydro generation profiles (March 2024).

5.4.2 Wind and Solar Sequences

As wind and solar have become more prominent sources of generation, they are now also modelled based off historic sequences where data is available. Historic wind and solar data is obtained from renewables ninja and starts in 1982, so includes 40 annual sequences. For years prior to this, we use a flat profile estimate based on a capacity factor, which is appropriate as the ERCs consider average energy generation over time.

5.5 Impact of Generation Assumptions on the ERCs

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.

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 if they reduce their capacity (and energy) the ERCs will increase, as again more controllable hydro generation is required to balance the demand.

6.0 Generator Outages in the Electricity Risk Curves

6.1 Outages Included in the ERCs

In the previous chapter, we discussed how generator behaviour is included 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.

In each monthly ERC update, we look at all of the generation outages over the next year that have been listed on the Planned Outage Coordination Process (POCP) website. We then select the outages we wish to include according to a set of criteria. The included outages for each month are published in the ERCs assumptions spreadsheet.

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 that any generator outages that can be deferred in an emergency situation will be deferred. This ensures the maximum possible generation fleet is available to prevent hydro storage levels dropping any lower.

Second, we typically only consider outages 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 for 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 also check with generators whether these outages would be deferrable in the event of a hydro shortage.

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.

6.2 Generation Type Specific Outage Criteria

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.

6.2.1 Thermal and Geothermal

All thermal and geothermal outages are included according to the above criteria (section 6.1). When these generators are on outage, more hydro storage will need to be consumed to cover for the loss of generation.

6.2.2 Wind

In addition to the above criteria (section 6.1), wind farm outages are also 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.

6.2.3 Run-of-River Hydro

All run-of-river hydro outages meeting the above criteria (section 6.1) 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.

6.2.4 Controlled Hydro

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. In this case, potential generation in the form of stored hydro is being lost, and this outage would be included in the ERC model.

6.2.5 Cogeneration

All existing cogeneration and respective outages are accounted for in the model using a profiled output (see section 5.3).

6.2.6 Solar

There is an increasing number of grid scale solar installations. If the above criteria are met (section 6.1), outage factors will be applied to solar generation in the model, based on the percentage of the solar farm on outage.

6.2.7 HVDC

We also include any 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, with most of the demand in the North Island. In the case when hydro storage is low, HVDC transfer will be in the south direction, with North Island generation supporting South Island demand. An outage of the HVDC will 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.

6.3 Impact of Outages on the ERCs

Outage assumptions are updated the most regularly of all assumptions and are one of the reason 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.

7.0 Transmission Assumptions in the Electricity Risk Curves

7.1 Transmission Security Constraints

We include transmission security constraints in the derivations of the ERCs, as they have the potential to constrain generation, particularly in a dry year. Transmission lines throughout New Zealand have limits to the electricity they can transmit. These limits can change depending on the time of year and hence have varying 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 it is important to include specific transmission line constraints because they could constrain generation, depending on which generators are generating and where demand is. An example of where constrained generation affects the ERCs, is where thermal generators which are brought online to conserve hydro generation may not be able to generate at full capacity because doing so may overload lines or compromise security standards on the power system.

7.2 Transmission Line Specific Constraints

The following table (Table 3) outlines the constraint equations and the transfer limits for each constraint. The pre-contingent steady state power flow on the two circuits listed must not exceed the transfer limit. These equations generally reflect what is observed in the wholesale market. However, as we generate constraints dynamically in the market using the Simultaneous Feasibility Test (SFT), the equations below will differ from those in the wholesale market. We do not consider there to be any material impact of these differences for the purposes of security of supply 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.

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 + 1*NMA_GOR_TMH1.1 + 1*NMA_GOR_TMH2.1 + 1*EDN_INV.1	1000

7.3 HVDC Constraints

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

Table 4: HVDC Transfer Limits.

HVDC	Limit (MW)
North Flow (BEN_HAY)	1000
South Flow (HAY_BEN)	550

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. Maximum south transfer is 550MW, so only up to 550MW of electricity can be delivered to the South Island.

7.4 Impact of Transmission Assumptions on the ERCs

Generally, the AC network constraints do not have a large impact on the ERCs. This is because 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 impact of the AC network generally allows a free flow of electricity.

This is not the case for the HVDC link between the North and South islands. 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 impacts the ERCs. HVDC capacity, like generation capacity, if increased will lower the ERCs and vice versa. Similarly, outages on the HVDC link will increase the ERCs.

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