TRANSPOWER

Upper South Island Upgrade Stage 1: Major Capex Proposal

Attachment 2: Need, Demand and Generation Scenarios

August 2025

Purpose

This attachment forms part of our Upper South Island Upgrade Stage 1 Major Capex Proposal (**MCP**).

The purpose of this document is to describe the investment need and to outline the demand and generation scenarios that we have used for our project analysis and application of the Investment Test. To apply the Investment Test, we must make assumptions about the future demand and generation in the region, which drive the need for investment. This attachment outlines the key demand and generation assumptions underpinning our analysis.

Contents

1 Need for investment

1.1 The existing system

The Upper South Island (**USI**) region comprises all the South Island north of Timaru and Tekapo. Figure 1 shows the 220 kV circuits within the region.

The USI is supplied by four 220 kV circuits which connect Christchurch to generation in the Waitaki Valley. These circuits are:

- a single circuit line from Twizel to Islington
- a single circuit line from Livingstone to Islington
- a double circuit line from Twizel to Islington and Bromley.

Three 220 kV circuits from Islington to Kikiwa supply the entire Nelson-Marlborough region and part of the West Coast region. The West Coast region is also supplied by two smaller 66 kV circuits from Islington to Hororata. However, their contribution is negligible compared to that of the 220 kV circuits.

From Kikiwa, there are two 220 kV circuits and two 110 kV circuits north to Stoke.

Demand in the USI region significantly exceeds the current electricity generation capacity, and the difference is supplied from outside the USI region. While there is considerable potential for future renewable generation, there are few committed projects in the region.[1]

Without significant commitment to local dispatchable generation, increasing demand will lead to greater flow over the 220 kV lines from the south, eventually resulting in binding capacity constraints. Based on our latest demand forecasts, the thermal capacity of the existing Ashburton–Timaru–Twizel circuits will be sufficient to maintain N-1 security until the 2028.

Voltage stability has also been a recurring issue in the region because power is transported long distances from the Waitaki Valley to Christchurch and further north to the top of the South Island. It is important that we maintain voltage within an acceptable range. Voltage outside of the acceptable range can cause power surges, power cuts, and severe impacts across the power system. Based on our initial investigations, the USI voltage stability constraint could start limiting growth by 2028.

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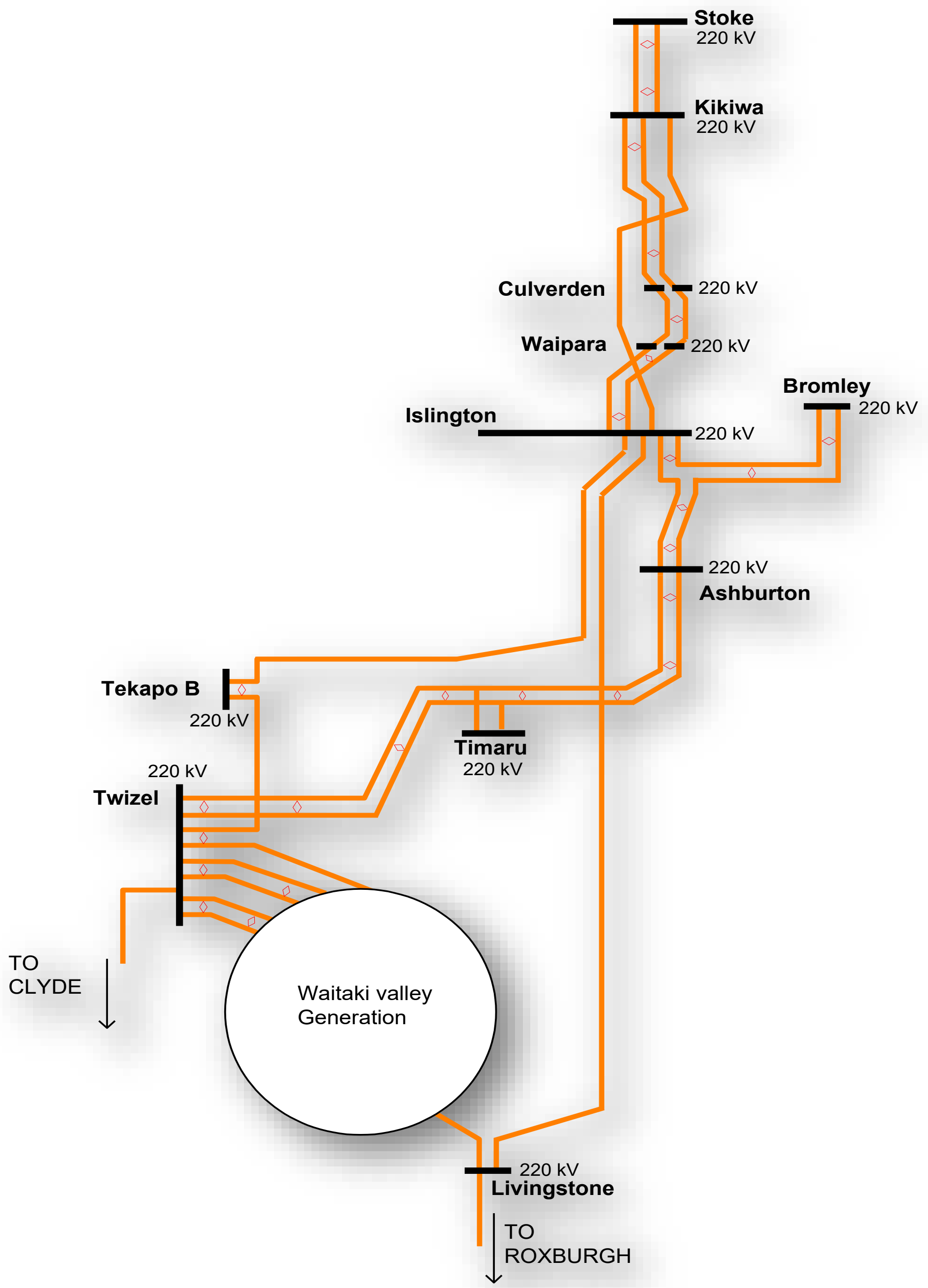
1 We have identified a considerable amount of potential new wind and solar generation in the region but this generation is not yet committed.

Figure 1: USI 220 kV transmission network



1.2 Prior investigations and investment

We have been monitoring the capacity and voltage stability issues in the USI for some time. To address these challenges, we have implemented various measures to enhance voltage stability:

- In 1996, we introduced a static VAr compensator (**SVC**) at Islington substation, known as SVC3.
- A larger SVC, SVC9, was added at Islington in 2010 along with an additional shunt capacitor bank. A Static Synchronous Compensator (**STATCOM**), STC2, was also added at Kikiwa in 2010.

- An 80 Mvar shunt reactor was added at Islington in 2023.

A third 220 kV line was commissioned from the Waitaki Valley to Islington[2] in 1975. These lines come together in close proximity in the 'close approach area' shown in Figure 2. This prompted consideration of a switching station in the area to connect these lines. A switching station would ensure that a line fault impacts only half the length of one of the four circuits, thereby reducing the severity of voltage disturbances.

A switching station is a type of substation that connects two or more circuits, allowing for flexibility in managing the flow of electricity. By providing alternative pathways for electricity in the event of a circuit outage, a switching station enhances system reliability and resilience.

In 2007, we acquired a parcel of land in this area (at Orari), with plans for a future switching station and potential supply point. Studies conducted in 2012 indicated a need for voltage support by 2014, based on assumptions of low overall demand growth, but with rapidly increasing irrigation loads in the area. However, uncertainties relating to the ongoing effects of the Christchurch earthquakes, the Pike River disaster and ongoing irrigation growth would potentially affect the need.

As such, we developed phased long-term development plans to ensure voltage stability in the USI until a new transmission line between the Waitaki Valley and Christchurch was eventually needed. As the immediate need was relatively urgent, but the overall outlook uncertain, we split the investment into two phases:

- Phase 1: Implementation of a new bus coupler at Islington.
- Phase 2: A more substantive investment, potentially involving larger-scale transmission assets to address longer-term needs.

In June 2012, we submitted the phase 1[3] proposal, which was subsequently approved by the Commerce Commission in February 2013.[4] This project included the installation of a sixth 220 kV bus coupler at Islington, which allowed for the decommissioning of end-of-life voltage stability equipment at Islington while also mitigating any short-term voltage stability concerns.

Phase 1 also provided funding to investigate potential switching station option(s) as part of the preparatory work for future phases. Following approval we commenced this investigation.

In March 2013, we consulted with stakeholders on our approach, assumptions and the long list of transmission and non-transmission options for USI phase 2. However, due to changes to our demand forecast, and low levels of demand growth, we initiated a review[5] of the need date for phase 2. This review led to the decision to put the phase 2 project on hold.

In 2014, we sought to amend the approved major capex project outputs for the phase 1 project.[6] The Commerce Commission approved the Outputs Amendment Application on 26 February 2015.[7] This amendment primarily involved the addition of provisions to secure designations and property rights for two potential future switching stations at Orari and Rangitata.[8] This change aimed to

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2 Christchurch to Twizel A, double circuit.

3 USI-Reliability-Proposal-Capex-Proposal-June-2012.pdf

4 Commerce Commission's decision and reasons paper for USI Grid Upgrade Stage 1 MCP, 13 February 2013.

5 This review reflected our general planning approach of regularly reviewing demand forecasts and need dates for major capital projects.

6 Transpower's application to amend the allowance and outputs for the USI Stage 1 Project - August 2014

7 Commerce Commission's Final decision on Transpower's application for an Outputs Amendment to Upper South Island Stage 1 - 26 February 2015.

8 These designations and property rights for both the Orari and Rangitata switching stations have now been obtained.

ensure that these switching station(s) could be commissioned promptly, during the next phase, if they were identified as part of the preferred option. While the Output Amendment preserved the possibility of building switching stations at these sites, it did not preclude this investigation ultimately leading to a different preferred solution.

Figure 2: Geographic map of USI region

1.3 Overview of the need for investment

1.3.1 Security standards

Our planning studies that support our Transmission Planning Report (**TPR**) regularly assess the needs of the national grid to ensure a reliable power supply across New Zealand. This planning includes maintaining a level of reliability during the immediate investment horizon based on prudent demand forecasts. As noted in our TPR[9], it is particularly important that we regularly review the needs of the USI region, as local demand is met through transmission lines from distant generation sources due to the relative shortage of local generation capacity.

The transmission lines supplying the USI region form part of the core grid, which is defined in the Electricity Industry Participation Code 2010 (**Code**) as a specific list of transmission assets[10].

The deterministic limb of the Grid Reliability Standards (**GRS**) require Transpower to maintain at least an N-1 reliability on the core grid. The N-1 standard ensures that the power system can remain stable and continue supplying power even if a single significant unplanned outage occurs in the core grid.

Investments on the core grid are made deterministically to meet the GRS N-1 reliability standard, by investing in the option which maximises expected net electricity market benefit, even when the net benefit is negative. This approach reflects the N-1 reliability standard as a necessary 'safety net' that underpins the core grid's operation, ensuring a reliable electricity supply to New Zealand.

1.3.2 Need

Investment is needed to meet the deterministic limb of the GRS. Demand in the USI region has been steadily rising over recent years, particularly during summer when irrigation loads peak. With the ongoing shift towards electrification, this trend is expected to continue. Currently electricity demand in the USI significantly exceeds the region's generation capacity. While there is considerable potential for intermittent renewable generation, we are unaware of any significant committed generation or battery storage projects that could mitigate the need. To avoid the need for transmission investment, the region requires generation or battery storage solutions with significant capacity to reliably reduce peak demand or inject power into the grid during peak load periods before 2028.

Without such firming generation or battery storage projects[11], this growing load will necessitate additional investment in both transmission capacity, to alleviate thermal constraints, and in voltage support, to ensure voltage remains stable after a fault.

Thermal constraints can be addressed either by constructing new transmission lines or enhancing the capacity of existing ones. Capacity upgrades can be achieved through targeted thermal up-rates, which allow the lines to operate at higher temperatures, thereby increasing their capacity.

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9 See Transpower – Transmission Planning Report 2023, sections 6.8.1 and 6.9.1.

10 The USI network is part of the core grid as defined in Schedule 12.3 of Part 12 of the Code (220kV Tekapo B-Islington, 220kV Twizel-Opihi-Timaru-Ashburton and 220kV Livingstone-Islington). The deterministic limb of the GRS is set out at clause 2(2)(b) of Schedule 12.2 of the Code (the N-1 reliability standard for the core grid) and provides that with all assets that are reasonably expected to be in service, the power system would remain in a satisfactory state during and following the tripping of a significant transmission asset in the core grid.

11 In addition to those already committed. See Section 4 of this document for further detail.

Alternatively, replacing the existing conductors with higher-capacity conductors can also alleviate constraints.

Both transmission owners and distribution lines businesses invest in voltage support devices or make changes to the configuration of their systems to reduce the need for voltage support. This ensures the power system recovers safely from faults, maintaining voltage within acceptable limits while minimising any loss of load. Additionally, increased generation capacity and demand response mechanisms provide alternatives to transmission investments by reducing peak demand on the transmission system.

Types of Voltage Support include:

- *Capacitor Banks (and shunt reactors)* provide a standard solution for static voltage issues, ensuring steady-state voltage stability. However, they do not offer rapid response during power disturbances, which is essential for maintaining voltage quality and preventing widespread supply loss.
- *Dynamic Reactive Support* is necessary during disturbances, requiring a fast (millisecond) response to stabilise voltage. Generators, synchronous condensers, Static Var Compensators (**SVCs**), and Static Synchronous Compensators (STATCOMs) all offer this rapid response and are commonly used for dynamic support.

Adjusting transmission configurations can also reduce the need for dynamic reactive support. For example, installing additional bus couplers reduces the number of assets lost during a fault. Similarly, segmenting long transmission lines by installing switching stations can reduce the length of the line lost during a fault, improving system stability.

Currently, static and dynamic reactive support in the USI is provided by a mix of capacitor banks, a shunt reactor and SVCs at Islington, along with a STATCOM at Kikiwa.

1.3.3 Need date and quantum

Our investigations indicate that the voltage stability constraints in the USI may start limiting demand growth by winter 2028. The thermal capacity of the Ashburton–Timaru–Twizel circuits is also sufficient to maintain N-1 security only until 2028. This is one year later than the need date in our 2023 TPR due to updated demand forecasts. The limits and the years when they are forecast to be exceeded are detailed in Table 1 and visually represented in Figure 3. Additionally, as demand in the region continues to grow, managing outages is likely to become more difficult, adding operational challenges.

Since our long-list consultation, we have done some further analysis on the impact of ~300 MW installed solar capacity in the USI to our need dates. Assuming a 15% solar contribution to our peak summer demand and zero contribution in winter, our need date remains in 2028, but only for static PV limit. Our thermal need date is shifted to 2029.

To inform the timing of investment we have used the prudent[12] variation on the Environmental scenario under EDGS 2019 forecast. We consider it is an appropriately prudent forecast to use in our planning and this was supported during our long-list consultation for the USI Upgrade project.

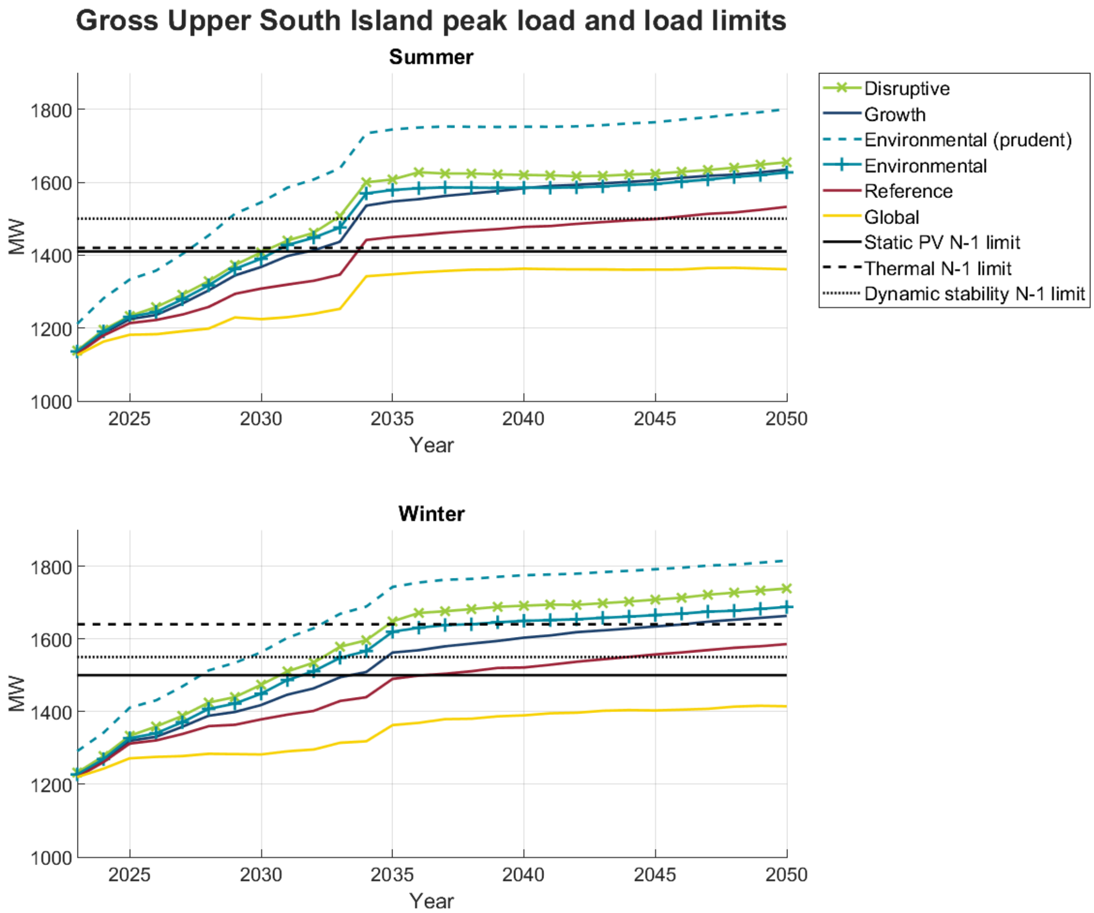
12 We use prudent peak demand forecasts in planning studies. This is equivalent to a P90 forecast, in which peak demand has a 90 per cent chance of being less than the prudent forecast. Put another way, we expect actual peak demand to exceed the forecast in just one year in ten. This is described in more detail in section 3.1.7.

Table 1: USI Thermal, Voltage Stability Limits and Forecast load year

Season	Thermal MW (N-1 limit)	Contingency[13]	Expected year of USI load exceeding limit (Prudent - Environmental)
Summer	1420	Ashburton–Timaru–Twizel–2	2028
Winter	1640	Ashburton–Timaru–Twizel–2	2033
	Static voltage stability MW (N-1 limit) – 5% margin		
Summer	1420	Ashburton–Timaru–Twizel–2	2028
Winter	1500	Livingstone–Norwood–1	2028
	Dynamic voltage stability MW (N-1 limit)		
Summer	1500	Ashburton–Timaru–Twizel–2 Islington–Tekapo B–1	2029
Winter	1550	Islington B–1	2030

13 A contingency is the loss or failure of a part of the power system (e.g., a transmission line). This is also called an “unplanned outage".

Figure 3: USI Transmission capacity and voltage stability constraint limits, MW



2 Approach to developing demand and generation scenarios

We conduct economic evaluations of options to meet the deterministic limb of the GRS using a range of market development scenarios i.e., demand and generation scenarios under the Capex IM. A market development scenario is an internally consistent set of input assumptions that represents a plausible future of the electricity system. Using demand and generation scenarios ensures that our economic analysis considers a range of different demand and generation futures.

A market development scenario includes assumptions about:

- future electricity demand, including assumptions regarding base demand, electric vehicle (EV) uptake, solar PV uptake, distributed energy storage, etc.,
- existing, decommissioned and future new generation connected to the national grid,
- capital and operating costs for both existing and future generation assets,
- availability of fuel for generation,
- fuel and carbon costs associated with generation, and
- grid-connected energy storage solutions.

The Investment Test uses the demand and generation scenarios produced by the Ministry of Business, Innovation and Employment (**MBIE**) or reasonable variations of its scenarios. MBIE's scenarios are called the Electricity Demand and Generation Scenarios (**EDGS**).[14]

For this investigation we have based our analysis on the 2019 EDGS with several updates and variations. We updated the 2019 EDGS to reflect consultation we undertook as part of the Net Zero Grid Pathways 1 (**NZGP1**) workstream in 2021 (we refer to these as the 2019 EDGS Variations)[15]. These updates aimed to ensure the EDGS reflect the potential for rapid change in New Zealand's energy sector and are plausible futures to use in our evaluation of investment proposals.

In addition, for this investigation we have updated some more specific information relating to demand in the USI region. The EDGS focus on national and island level demand, meaning we must use a variety of allocation mechanisms to allocate the national and island level information to the regional and Grid Exit Point (**GXP**) levels to complete our analysis. To do this, we also incorporate information from electricity lines companies about GXP level growth. We have also updated some of our generation assumptions to reflect more recent information.

The 2019 EDGS and our 2019 EDGS Variations consist of five scenarios:

1. **Reference:** Current trends continue.
2. **Growth**: Accelerated economic growth.
3. **Global:** International economic changes.
4. **Environmental:** Sustainable transition.
5. **Disruptive:** Improved technologies are developed.

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14 See https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-modelling/electricity-demand-and-generation-scenarios/

15 See Consultation on EDGS 2019 Variations to develop generation scenarios | Transpower

The assumptions used in our demand forecast remain consistent with our short-list consultation.[16]

In July 2024, MBIE released a new version of EDGS. We have continued to base our analysis on the 2019 EDGS variations we have developed and consulted on as the foundation of our analysis. We note that the new EDGS contains limited regional information, such that if we were to adopt them, we would still have to draw heavily on the regional detail we have gathered for this project. Our view is that the 2019 EDGS Variations and our forecasts presented below provide a suitable basis for assessing this project.

3 Demand assumptions

This section presents the USI market development demand forecasts we have used for this investigation.

3.1 Regional forecasts and assumptions

Figure 4 and Figure 5 present our proposed peak and energy demand forecasts, respectively, for the USI region for each of the five NZGP1 EDGS scenarios.[17] Table 2 and Table 3 present the summer and winter peak forecasts in 2025, 2030 and 2050, broken down by the factors that are contributing to that growth:

- Base demand – the underlying growth in demand driven by factors such as population and economic growth.
- Step loads – new demand that might appear in the future from new developments, such as new commercial and residential developments.
- EV – the uptake of EVs and the "smartness" of their charging.
- Solar – the uptake of residential and commercial solar photovoltaic panels.
- Battery – the uptake of residential and commercial battery storage packs.
- Process heat electrification – the electrification of industrial processes such as the conversion of coal and diesel boilers to electric boilers.

Each scenario has different assumptions relating to each of these factors that leads to the overall variation in the forecasts. We explain our approach to determining each of these factors in more detail below.

We include forecast demand at the Studholme GXP in our summer peak demand forecast, but not in our winter forecast. This is because of the Studholme 110 kV Split: in summer, the connection to the Waitaki circuits is opened and the Studholme GXP is connected to the grid via the Studholme–Timaru circuit, which is considered part of the USI region electrically, while in winter Studholme is supplied by the Waitaki circuits, which are not considered part of the USI, electrically.

16 See Upper South Island upgrade project - short-list consultation | Transpower

17 Appendix B shows the associated national peak and energy demand forecasts.

Figure 4: USI peak demand forecast, MW

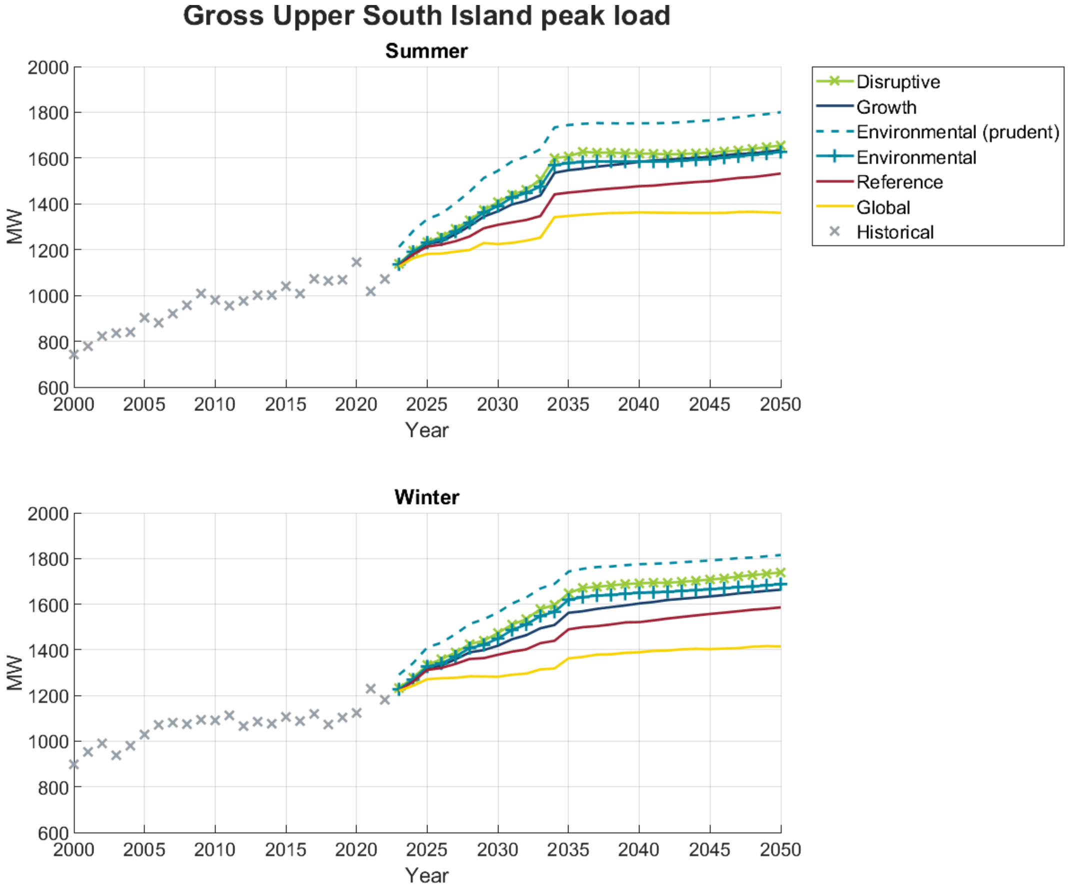


Figure 5: USI energy demand forecast, TWh per annum

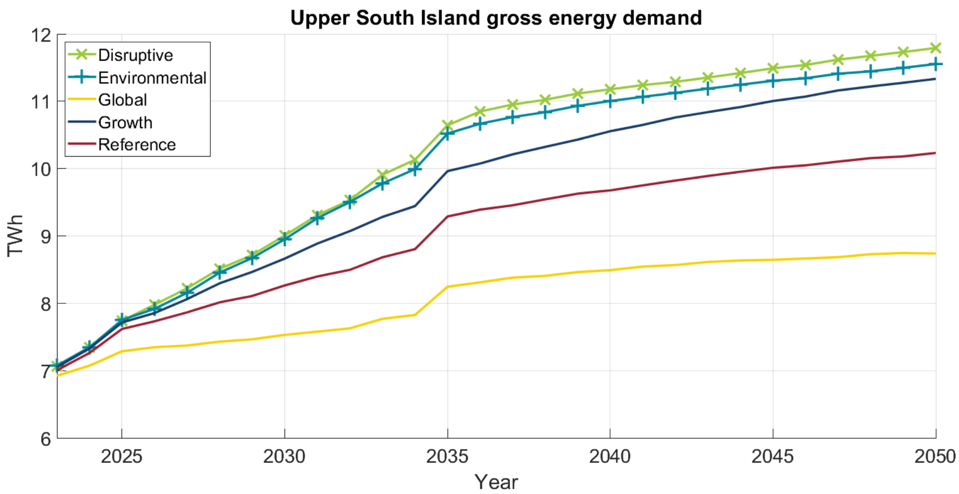


Table 2: USI winter demand forecast assumptions, MW

Scenarios	Year	Peak	Base	Step loads[18]	EV	Solar	Battery	Process heat electrification
Disruptive	2025	1333.6	1220.9	73.9	18.1	-1.9	-0.2	24.4
	2030	1473.9	1234.8	141.9	35.2	-5.8	-1	90
	2050	1738.5	1267.5	185.7	196.3	0	-95.6	213.7
Growth	2025	1319.7	1228	66.1	7.3	-1.7	-0.2	21.8
	2030	1418.1	1257.3	114.6	15.9	-3.7	-0.4	57.1
	2050	1663.2	1353.9	133.7	124.4	0	-56.1	130.5
Environmental	2025	1326.9	1224.9	66.1	15.9	-1.8	-0.2	24.2
	2030	1449.3	1247.7	114.6	29.7	-5	-1	87.2
	2050	1687.8	1324	133.7	136.4	-1.4	-89.9	208.4
Reference	2025	1312.1	1224.3	64.4	7.5	-1.6	-0.6	20.9
	2030	1378.6	1244.2	90.1	16	-3.3	-0.9	45.5
	2050	1585.7	1304.6	96.4	120.7	0	-26.7	101.3
Global	2025	1271.5	1217.5	34.1	8.2	-0.9	-0.1	20.1
	2030	1282.0	1218.1	37.3	21.3	-1	-0.2	36.3
	2050	1414.6	1208	37.7	122.7	0	-16	79.2

[18] We show the maximum demand of each step load instead of their demand at the time of USI peak. This gives a clearer indication of the variation in step loads between scenarios.

Table 3: USI summer demand forecast assumptions, MW

Scenarios	Year	Peak	Base	Step loads[18]	EV	Solar	Battery	Process heat electrification
Disruptive	2025	1232.9	1128.9	63.1	19.5	-10.9	-0.3	27.9
	2030	1407.7	1145.3	125.2	36	-28	-1.2	117.5
	2050	1654.8	1195.8	184.3	186.5	-64.1	-78.3	242.7
Growth	2025	1224.5	1140.5	55.3	8.5	-8.6	-0.2	22.9
	2030	1367.5	1181.9	98.4	15.8	-19.1	-0.4	76.7
	2050	1634.2	1336.2	117.9	115.8	-53.8	-49.5	169.2
Environmental	2025	1230.9	1136.1	55.3	17.2	-10.3	-0.3	27.4
	2030	1390.1	1166	98.4	29.4	-27.5	-1.2	113.4
	2050	1626.9	1277.9	117.9	128.2	-54.6	-72.9	234
Reference	2025	1213.5	1132.6	53.3	8.9	-7.3	-0.5	20.8
	2030	1308.3	1162.7	70.4	17.9	-16.5	-0.8	60
	2050	1532.6	1258.6	74.9	115.3	-40.3	-25.6	139.9
Global	2025	1181.6	1119.6	31.4	9.8	-4.4	-0.1	20
	2030	1224.4	1125.4	34.2	20.2	-8.1	-0.2	50.9
	2050	1361.3	1124.5	34.6	104.4	-28	-15.2	130.8

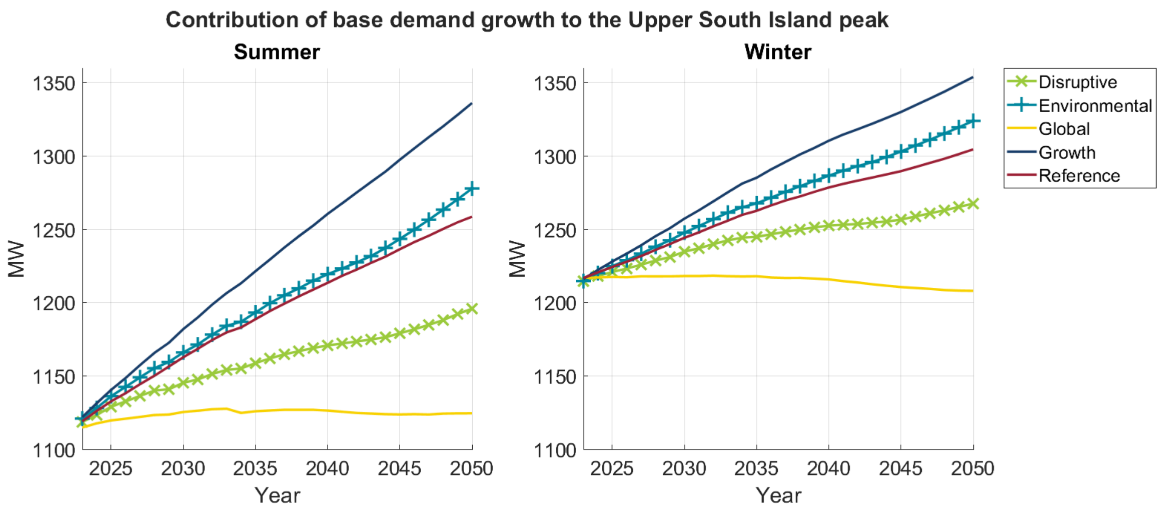
3.1.1 Base demand

Base level demand relates to underlying demand increases we expect to occur from factors such as economic and population growth.

We model base demand by combining national and island level base demand energy forecasts informed from our NZGP1 EDGS variations, with GXP level peak base demand forecasts from local electricity distribution businesses (**EDBs**). We use a reconciliation approach where we develop half-hourly GXP demand profiles that sum nationally and by island to align with national and island level NZGP1 EDGS base demand forecasts. This approach ensures that the aggregated demand profiles are consistent with the national and island levels, while also maintaining strong alignment with GXP-level forecasts. GXP-level forecasts provided by EDBs are given higher weighting in the reconciliation process in early years to place higher value on nearer term information from EDBs. Modelling demand profiles is important as factors such as EV charging and residential/ commercial battery use will have a significant impact on future peak demand.

Figure 6 shows the resultant base peak demand forecasts for the USI. It is notable that the growth associated with the Global scenario is very low reflecting the low national growth rate associated with this scenario in the EDGS.

Figure 6: Base demand growth, MW



3.1.2 Step loads

New step loads are expected to play a major role in driving growth in the region over the next 10 years. These are new developments expected to occur in the region that will lead to a step increase in electricity demand. Figure 7, Table 2 and Table 3 show that step loads contribute between 34.2 MW and 141.9 MW to peak load growth by 2030.

We model step changes by assigning a half-hourly demand profile to each step change based on the type of demand expected (e.g., industrial, residential etc.) and then scaling so that the peak of the profile aligns with the expected peak demand of the step load. We then add this profile to the existing forecast demand at the GXP where the step is expected.

Distribution companies and industrial companies have provided us with details of the step loads expected in the region. We have also included possible electrification of boilers identified from the

Mid-South Canterbury RETA report and the West Coast RETA report. Where a step load appears to be also captured in another modelled component (e.g. process heat) we reduce the other modelled component by the size of the step change to reduce the chance of double counting.

Table 4 lists the major new developments we are aware of and have incorporated into our scenarios. We have varied the inclusion of step loads across the scenarios with all of them being included in the Disruptive scenario where a widespread electrification of industry is seen as most likely. In the other scenarios we have omitted some of the less likely step changes. This process adds diversity across our scenarios and reflects that not all new step loads may appear or be as large as expected.

Based on feedback from the long-list consultation we have included electrification of aviation at Christchurch airport as step loads. This is only in the Growth, Environmental and Disruptive scenarios, with twice as much aviation electrification in the disruptive scenario.

Table 4: Step loads in the USI

Step load	GXP	Scenarios
Cook Strait Ferry electrification	Blenheim	All scenarios
Winery expansion	Blenheim	Disruptive only
ANZCO Kokiri	Dobson	All scenarios except Global
Mines on the West Coast	Dobson	Disruptive scenario only
Westland Milk Product load increases	Hokitika	Disruptive scenario only
Westland Milk Product expansion	Hokitika	All scenarios
Dairy electrification	Kimberly and Hokitika	Disruptive scenario only
Coal boiler conversions on the West Coast	Greymouth, Dobson, Hokitika and Reefton	All scenarios except Global
KiwiRail Otira	Otira	Disruptive scenario only
Heat pumps at various schools	Ashburton 66 kV	All scenarios
Coal boiler electrification in Ashburton	Ashburton 66 kV	Disruptive scenario only
Various step loads at Hororata	Hororata 66 kV	All scenarios except Global

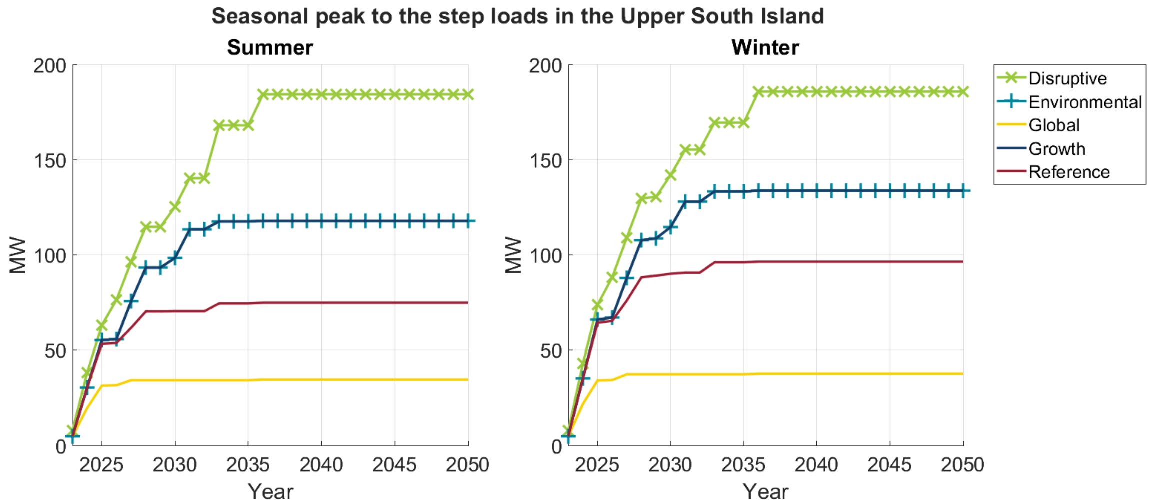
Step load	GXP	Scenarios
Various step loads at Islington 66 kV	Islington 66 kV	All scenarios except Global
Various step loads at Timaru	Timaru	All scenarios
Various step loads at Temuka	Temuka 33 kV	All scenarios except Global
Various step loads at Tekapo A	Tekapo A	All scenarios except Global
Boiler electrification identified from the Mid-South Canterbury RETA report	Ashburton 66 kV, Studholme and Timaru	Disruptive scenario only
Electrification of Clandeboye dairy plant	New GXP	Environmental, Disruptive and Growth scenarios
Electrification of aviation at Christchurch airport	Islington 66 kV	Environmental, Disruptive and Growth scenarios
Westimber electrification identified from West Coast RETA report	Dobson	All scenarios
Westland Milk Products boiler electrification	New GXP	Disruptive scenario only
Fonterra Studholme boiler electrification	New GXP	Disruptive scenario only

Our step loads consider the potential electrification of dairy operations in the USI, specifically the Fonterra Studholme, Westland Milk Products and Fonterra Clandeboye sites. We also consider Fonterra Darfield electrifying in our process heat model (see Section 3.1.6 for more details on this model). Electrifying these sites would likely necessitate additional investment, so we model their electrification at a new GXP. The need date is determined by the Environmental scenario, and we only consider the electrification of the Clandeboye and Darfield sites for this purpose.

The step load information was mainly collected at the start of this project. We are aware that some steps have reduced in likelihood (e.g., Cook Strait ferry electrification). However, based on the latest feedback we have had from EDBs and large users in the USI, expectations around new step loads in the near to medium term remain strong, such that we consider our current assumptions remain reasonable.

Figure 7 shows the maximum demand each step load can contribute to the USI peak demand. Their actual contribution to the USI peak may be less, and vary from year to year, due to the nature of modelling the step loads using profiles. Note the demand due to step loads is the same in the Growth and Environmental scenarios.

Figure 7: Step load growth contribution



3.1.3 Electric vehicles

We have aligned our national EV assumptions closely with our NZGP1 EDGS variations. We model the impact of EVs by first adopting the assumed national uptake rates of EVs (broken into light, and heavy categories) as given by each NZGP1 EDGS variation scenario. National uptake rates are then allocated at a regional level using the light passenger vehicle kilometres travelled in each region, and at a GXP level using the number of relevant Installation Control Points (**ICPs**) behind each GXP.

For peak demand forecasts, it is also critical to make assumptions about when EVs will be charged. We model the timing of EV charging by assuming some proportion of EVs have a fixed profile (e.g., they tend to charge after work or when it is convenient) and the remaining proportion have a "smart" profile, and charge in a way that avoids regional peaks. In our demand forecasting models, the charging of "smart" EVs is moved to avoid peak periods. In this way, "smartness" reduces our peak demand forecasts.

We have aligned our "smartness" assumptions with our NZGP1 EDGS variations except we have reduced the "smartness" in the Disruptive scenario from 60% to 50%, such that 50% of all EV demand is "smart" charging by 2050. We have done this to create some additional diversity in our forecasts and to recognise that there are risks that EV charging may be less smart. Table 5 summaries the "smartness" assumptions for all scenarios.

Table 5: EV Smartness Assumptions, by scenario, by 2050[19]

	Disruptive	Growth	Environmental	Reference	Global
Proportion smart charging %	50 %	50 %	60 %	40 %	20 %

Figure 8 and Figure 9 shows the resulting megawatt contribution that fixed and smart EV charging each make to the USI peak demand. As is demonstrated, "smart" EV charging is very effective in

19 NZGP1 Scenarios Update December 2021

avoiding peak periods, with a contribution of less than 25 MW under all scenarios. Note that in Figure 9, the amount of smart charging at the time of peak decreases towards 2050. This is due to the dynamic nature of how smart EVs are modelled and the time of the USI peak moving. That is, the peak time is moving to a time during the day that has less smart charging. The decrease in the amount of smart EV charging is very small in comparison to the USI peak load shown in Figure 4.

Figure 8: Fixed electric vehicle demand growth

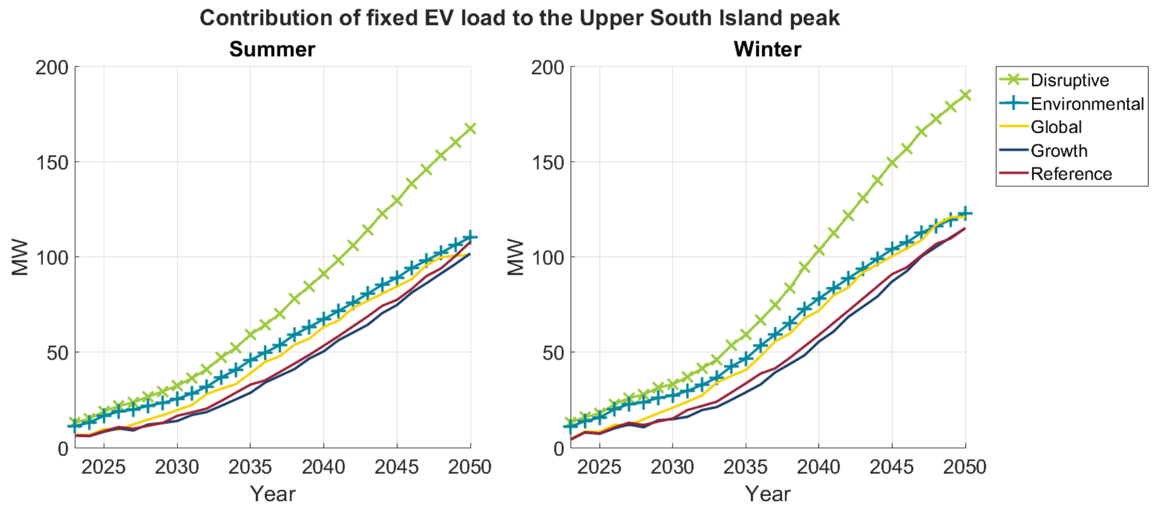
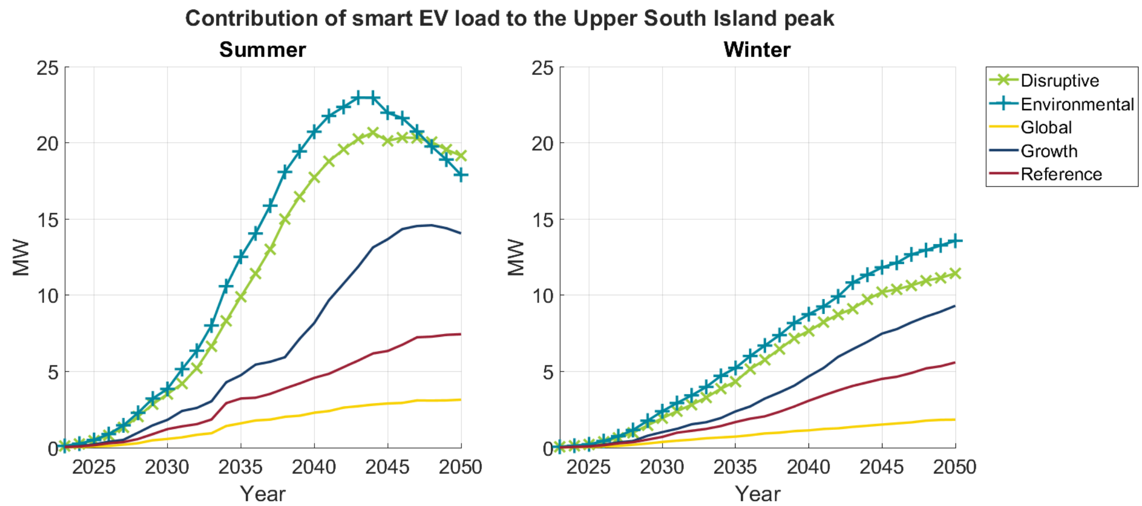


Figure 9: Smart electric vehicle demand growth



3.1.4 Solar uptake

We have aligned our national level solar and residential/commercial uptake rates with the assumptions we consulted on in developing the NZGP1 EDGS variations.

We model solar uptake by adopting national uptake rates consistent with our NZGP1 EDGS variations. We then allocate the national uptake rates to a GXP level using the number of ICPs behind each GXP and the solar propensities for each region. In Table 6 we give the number of solar installations in the USI for each scenario[20]. Based on EMI data we understand currently there are approximately 15,000 solar installations in the USI.

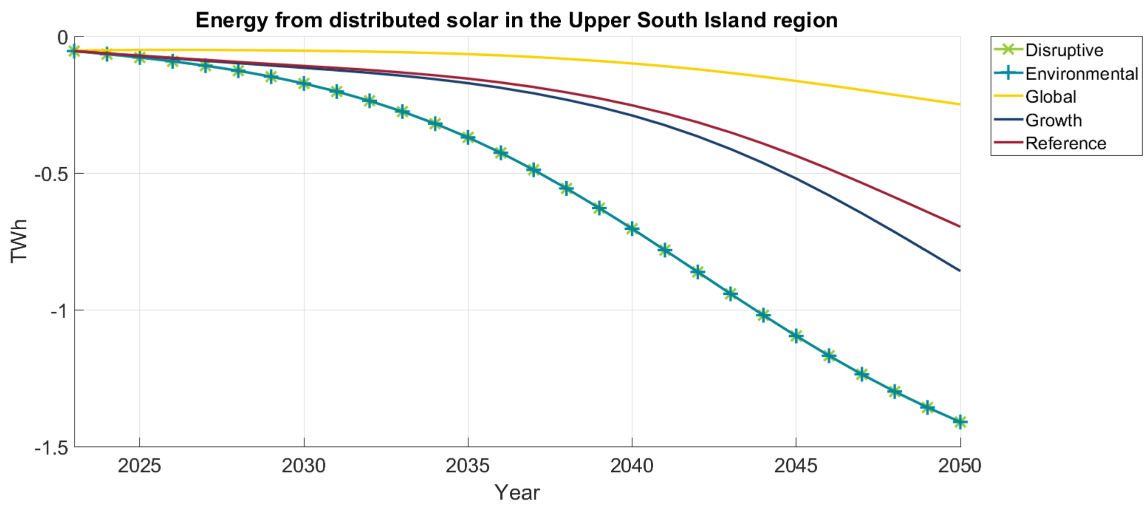
Table 6: Approximate Solar installations in the USI, by scenario and year

	Disruptive	Growth	Environmental	Reference	Global
2025	17,050	15,646	17,050	15,298	10,026
2030	42,871	28,363	42,871	26,593	12,465
2050	357,625	217,740	357,625	176,628	63,215

We use solar irradiance data at a regional and hourly level to estimate the amount of solar generation that is being produced at a half-hourly level.

Figure 10 shows the contribution of new residential/commercial solar installations to USI energy (TWh) demand. Note that solar generated electricity reduces the amount of electricity needing to be supplied from the GXPs (i.e., solar uptake reduces demand forecasts during the times of day it can produce electricity). As shown in Table 2, solar output reduces the winter peak by a small amount as peak demand tends to be outside solar operating times. As shown below, the Disruptive and Environmental scenarios have the same solar uptake.

Figure 10: Solar demand growth production contribution to demand, TWh



20 Assuming 3 kW per installation.

3.1.5 Battery uptake

We have aligned our battery uptake with the approach taken in our NZGP1 EDGS variations and set it as a percentage of solar uptake. We assume that the battery allocation at a GXP level is the same as the solar allocation. We also assume that EV batteries are available to reduce peak demand. In Table 7 we give the number of batteries in the USI for each scenario.

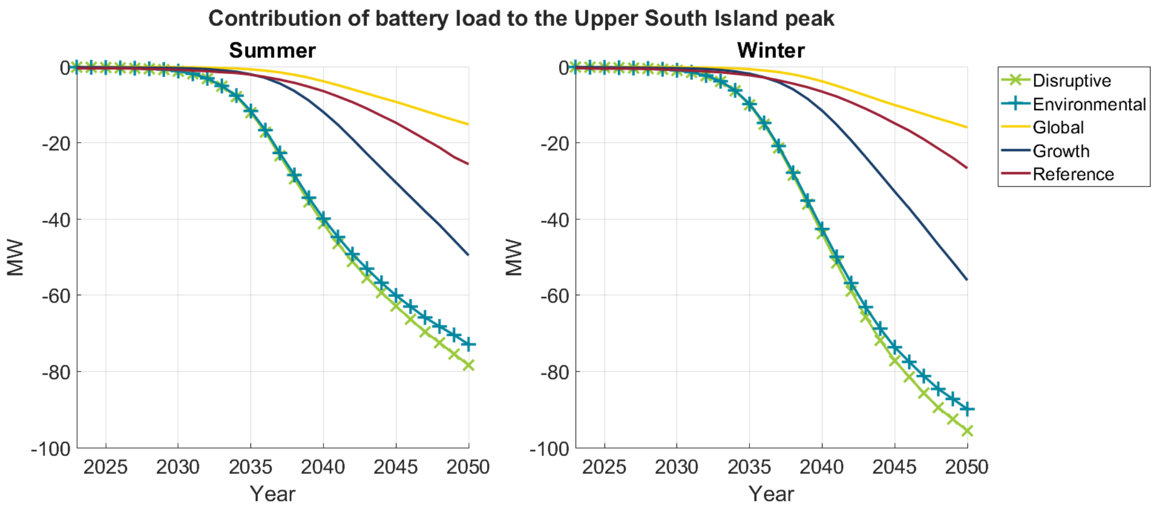
Table 7: Approximate number of battery installations in the USI, by scenario and year

	Disruptive	Growth	Environmental	Reference	Global
2025	452	391	452	1,143	251
2030	1,894	820	1,894	1,767	360
2050	171,949	104,219	171,949	47,225	30,257

We assume batteries are charged in trough periods and discharged in peak periods in such a way as to reduce the overall peak demand. In our modelling, batteries are assumed to reduce the daily peak load at a GXP.

Figure 11 shows the resultant contribution of new residential/commercial batteries to USI peak demand.

Figure 11: Battery uptake demand growth, MW



3.1.6 Process heat

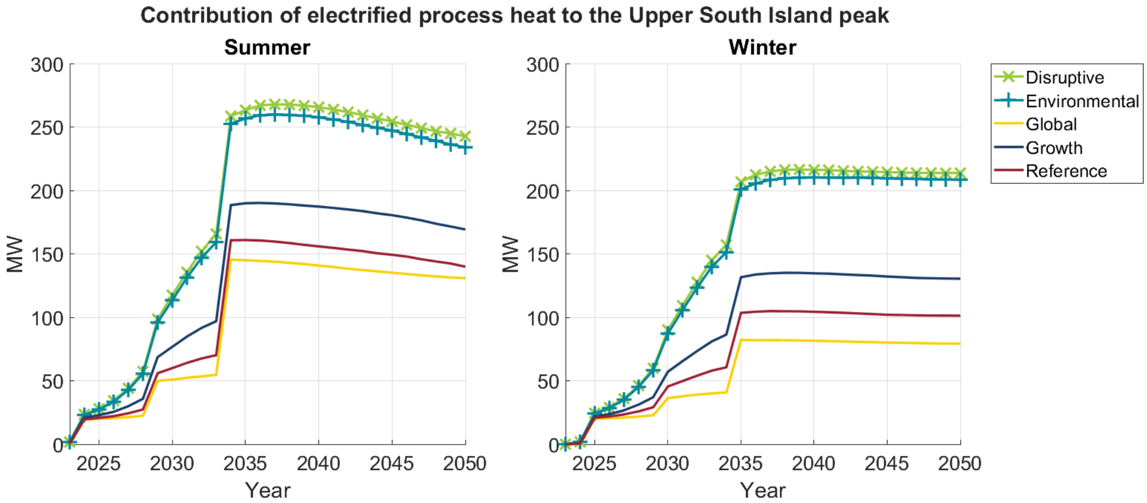
We have aligned our process heat 2050 totals closely with our NZGP1 EDGS variations.

However, we have updated the trajectory of heat electrification to follow an s-curve. An s-curve is a more common form of uptake for new products. It has some period of ramp up in uptake followed by a flattening in uptake. In addition, high-temperature process heat, which is used in industries requiring heating above 300°C, such as chemical manufacturing and metal melting, is not prevalent in this region. Therefore, we have eliminated the uptake of high temperature heat electrification in the Disruptive scenario (which was the only one to include it), as we are not aware of significant amounts of high temperature heat processing in the USI that could be electrified.

We model heat electrification by allocating national totals for different temperature heat electrification to a region using data on energy use by sector, fuel type and technology. We allocate the heat load at a GXP level using boiler databases, knowledge of major plants on the grid and by identifying any step loads which are electrifying process heat.

Figure 12 shows the resultant contribution of new process heat electrification to the USI. During summer, solar and battery contributions can shift the peak demand time. Consequently, the amount of electrified process heat contributing to the peak decreases at this new peak time. The step in 2034 is due to the electrification of the Fonterra Darfield dairy plant.

Figure 12: Process heat demand growth



3.1.7 Planning forecast

As a prudent asset manager, we want to invest in a timely manner to ensure we can supply demand in all but the most unusual circumstances. While the forecasts outlined above take account of many of the potential drivers of growth in the USI they do not account for the potential for peak demand to be high due to an unusual event, such as a cold weather event.

To address this concern, we have produced a prudent version of the Environmental forecast as mentioned in section 1.3.3. The prudent Environmental forecast is the same as the Environmental forecast above but adds a margin to account for the year-to-year variability of demand due to factors such as weather and system conditions. As with the Environmental forecast, it includes most but not the most speculative step loads increases. We have used this forecast to inform the need and timing of investment in our development plans.

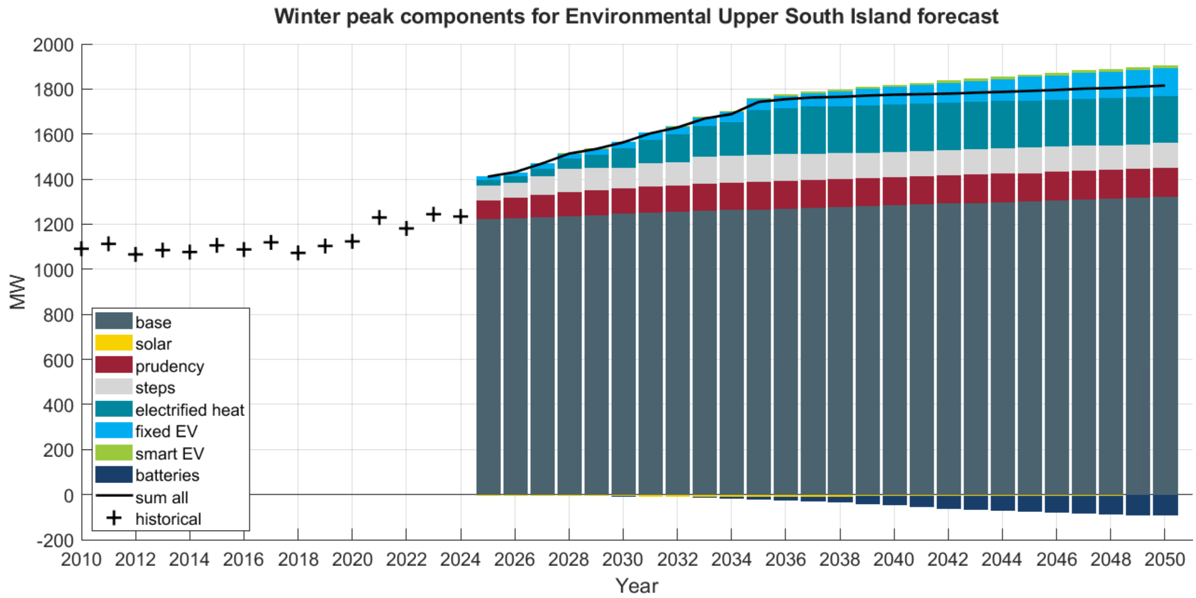
To derive the prudent component, we have:

1. Used regression analysis to regress historical peak demand against time

2. Determined the expected value and regression statistics associated with the variance of the regression fit.
3. Calculated the ratio of 10% probability of exceedance value to the expected value for the first 7 forecasted years and then maintained this ratio for the remainder of the forecast period.
4. Applied the ratio to the Environment forecast.

This is illustrated in Figure 13. As seen the prudent component is approximately 7% of total peak demand in 2050. If the prudent component was the only factor added to the base forecast demand, then the forecast in 2025 would be only 6% higher than the 2024 peak. Our view is that the prudent component is relatively modest and appropriate to use for planning.

Figure 13: Prudent planning forecast broken down by component



The other scenarios have been used to assess economic benefits with the timing of investment based on the prudent Environmental scenario. For example, although we have calculated the benefits (to use in the Investment Test) using the Disruptive scenario, the timing of the upgrades in each short-listed option has been informed by the prudent Environmental forecast.

3.1.8 Demand forecasts in other regions

The focus of this investigation is on the USI, so we have focused our commentary on the forecasts we intend to use for this region. However, we have developed a full set of forecasts for the rest of New Zealand. In Appendix B, we present the national peak and energy forecasts we have used, in combination with our USI forecasts for this project.

When we conducted the analysis to inform our long list consultation there was still uncertainty over the future of demand at the Tiwai Point Aluminium Smelter (Tiwai). However, it has now been announced that the contract has been extended to the end of 2044, with an exit option available from the end of 2034. Consequently, we have updated our forecast to reflect this increased certainty about Tiwai's future, and we now assume that Tiwai will remain open throughout the analysis period.

3.1.9 Updates from NZGP1

We have based our assumptions on those made as part of our NZGP1 project. However, as detailed above, we have made some refinements to the data and approach we used since deriving forecasts for our NZGP1 project. These include:

- updating data based on recent historical information and feedback from EDBs
- decreasing the "smartness" of EV charging in the Disruptive scenario from 60% to 50%
- amending the uptake rate of process heat to be a s-curve and removing the conversion of high temperature heat from the Disruptive scenario
- assuming Tiwai remains open throughout the forecast horizon.

3.1.10 Updates during the USI project

We have made some changes to our forecasts during this project. These relate to:

- having Tiwai operating throughout the forecast period
- refining our demand forecasting models. This change resulted in small changes to the USI forecasts and some changes to our forecasts outside of the region
- updating our process heat allocation to use a more recent database from DETA
- introducing aviation electrification at Christchurch Airport as step loads
- adding step loads identified from the West Coast RETA report
- including potential electrification of Westland Milk Products and Fonterra Darfield dairy plants in the USI.

3.2 GXP forecasts

More detailed information relating to the forecasts assumed at each GXP in the USI is provided in Appendix C and the accompanying spreadsheet.

4 Generation assumptions

This section presents information relating to the generation assumptions we have used for this project. Generation assumptions apply to our:

- Dispatch model, **SDDP**, which simulates the wholesale electricity market by calculating a least cost optimal dispatch over the study horizon.
- Generation expansion plan model, **OptGen**, which determines the location, timing, and technology of new (modelled) generation.

We use these models to evaluate the electricity market benefits for different investment options. For more information on this modelling refer to Attachment 6.

4.1 Basis of our assumptions

Generation assumptions for our SDDP and Optgen modelling are based on the Benefit-Based Charges (**BBC**) Assumptions Book v.2.0 ("Assumptions Book")[21].

4.2 Existing generation

Only a small proportion of the total generation capacity in the South Island is located within the USI, making it a net importer of electricity. All the grid-connected generation in the region is hydro, primarily concentrated at the southern boundaries of the region. The largest generators in the USI are the Tekapo A and B hydro stations, which feed into the Waitaki scheme, supported by a moderate amount of water storage in Lake Tekapo. Additional generation sources include the Coleridge hydro power station in Canterbury, which flows into the Rakaia River, and the Branch River scheme in Marlborough.

We include all grid-connected hydro generation in our model. Table 8: summarises the plant locations and rated capacities. We also model 'embedded generation' greater than 10 MW. Smaller embedded generation (<10 MW) is included in the demand forecasts as a reduction in gross demand. Smaller embedded generation include for example, the Dillmans power scheme embedded in Westpower's network at the Kumara GXP and the Opuha power scheme embedded in Alpine Energy's network at the Albury GXP. We assume that all existing generation will continue to operate throughout the analysis period.

Table 8: Existing USI Generation

Type	Modelled Transmission Node[22]	Name	Capacity (MW)
Hydro	STK066	Cobb*	32
Hydro	COL066	Coleridge	39
Hydro	TKA110	Tekapo A	30
Hydro	TKB220	Tekapo B	160
Hydro	ASB066	Highbank*	25
Hydro	ARG110	Argyle	3.8
Hydro	ARG110	Branch River	7

*embedded generation.

21 See the Assumptions Book site.

22 We model the AC transmission network down to 66 kV in SDDP. Generation which connects below this level is represented at a nearby model node.

4.3 Committed generation

In our generation expansion modelling we include 'committed' generation projects which we judge as likely to proceed. The timing of these builds is exogenously specified in the generation expansion model based on publicly reported development schedules. The criteria for classifying a project as committed are specified in the Capex-IM.[23]

In our economic analysis we have treated the Lauriston Solar Farm and Kōwhai Park Solar Farm as committed. We assume that Lauriston will be completed in 2025 and Kōwhai Park by 2027.

4.4 Potential generation

There is considerable interest from established and prospective generators in developing solar generation in the Canterbury region, with over 1 GW of solar projects registered through Transpower's Generation Connections Pipeline.[24]

While there is considerable interest, there is also significant uncertainty in what new generation may be build. For example, Orion informed us of several new generation developments, but on further investigation we understand the certainty of this generation has significantly reduced.

We have chosen a conservative approach in our base economic modelling, noting that there is considerable uncertainty in this area, and assumed new generation is limited to the Lauriston Solar Farm and Kōwhai Park Solar Farm[25]. However, to investigate the sensitivity of the results to higher levels of generation, we have considered some sensitivities:

- The planning studies have focused on considering the impact of a large increase in solar generation in the USI. This is described in Attachment 10.
- In our benefit modelling we have also considered the potential future influence of BESS and wind generation. This is described in Attachment 6 and summarised in Attachment 4.

23 Transpower-Capital-Expenditure-Input-Methodology-Determination-consolidated-as-of-29-January-2020.pdf, clause D8(1).

24 Connection enquiry information | Transpower

25 In June 2025 Loadstone announced its intention to commence construction on a 28MW solar plant at Clandeboye and we are aware of a 12.6MW solar farm being constructed in Marlborough. We have not considered these plants in our base analysis. Both these plants are relatively small and are well within the range of the new generation in the sensitivities we have considered.

Appendix A: Proposed EDGS and BBC Assumptions Book variations

Below we summarise the main EDGS and BBC Assumptions Book variations we have used for this project.

A.1 EDGS variations

Table 9: Demand variations

<table>
<tr><th>Assumption</th><th>2019 EDGS Value</th><th>Variation from EDGS</th><th>Rationale</th></tr>
<tr><td>Tiwai closure</td><td>Tiwai stays open in all scenarios. The reference scenario has a sensitivity case where Tiwai closes in 2030</td><td>Tiwai remains operational in all scenarios.</td><td>See Section 3.1.8 – Demand forecasts in other regions – for a discussion of our assumptions about Tiwai's closure.</td></tr>
<tr><td>Base energy growth rate</td><td><table>
<tr><td>Scenario</td><td>CAGR (%)[26]</td></tr>
<tr><td>Reference</td><td>0.8</td></tr>
<tr><td>Growth</td><td>1.2</td></tr>
<tr><td>Global</td><td>0.2</td></tr>
<tr><td>Environmental</td><td>0.9</td></tr>
<tr><td>Disruptive</td><td>0.7</td></tr>
</table></td><td><table>
<tr><td>Scenario</td><td>CAGR (%)</td></tr>
<tr><td>Reference</td><td>0.5</td></tr>
<tr><td>Growth</td><td>0.7</td></tr>
<tr><td>Global</td><td>0.1</td></tr>
<tr><td>Environmental</td><td>0.6</td></tr>
<tr><td>Disruptive</td><td>0.4</td></tr>
</table></td><td>Consistent with NZGP1</td></tr>
<tr><td>Electrification of Process heat</td><td>2050 energy demand:<table>
<tr><td>Scenario</td><td>2050 demand by temperature (TWh)</td></tr>
<tr><td>Reference</td><td>Low: 1.2</td></tr>
<tr><td>Growth</td><td>Low: 1.9</td></tr>
<tr><td>Global</td><td>Low: 1.2</td></tr>
<tr><td>Environmental</td><td>Low: 1.9
Med: 4.6</td></tr>
<tr><td>Disruptive</td><td>Low: 1.9
Med: 4.9
High: 6.5</td></tr>
</table></td><td>2050 energy demand:<table>
<tr><td>Scenario</td><td>2050 demand by temperature (TWh)</td></tr>
<tr><td>Reference</td><td>Low: 4</td></tr>
<tr><td>Growth</td><td>Low: 5.1</td></tr>
<tr><td>Global</td><td>Low: 3.2</td></tr>
<tr><td>Environmental</td><td>Low: 5.1
Med: 3</td></tr>
<tr><td>Disruptive</td><td>Low: 5.1
Med: 3.2
High: 0</td></tr>
</table>Process heat electrification has been modelled using an updated s-curve.</td><td>The amount of low and medium temperature process heat is consistent with NZGP1. Conversion of high temperature heat has been removed since no high temperature process heat was identified in the USI (this only affects the disruptive scenario). A s-curve has been used to better reflect the likely path of electrification.</td></tr>
</table>

[26] Compound Annual Growth Rate.

<table>
<tr><th>Assumption</th><th>2019 EDGS Value</th><th>Variation from EDGS</th><th>Rationale</th></tr>
<tr><td>EV demand</td><td>2050 energy demand by scenario (No assumptions around smartness given)
<table>
<tr><td>Scenario</td><td>2050 EV demand (TWh)</td></tr>
<tr><td>Reference</td><td>4.1</td></tr>
<tr><td>Growth</td><td>5.0</td></tr>
<tr><td>Global</td><td>3.2</td></tr>
<tr><td>Environmental</td><td>7.6</td></tr>
<tr><td>Disruptive</td><td>7.6</td></tr>
</table></td><td><table>
<tr><td>Scenario</td><td>2050 EV demand by smartness (TWh)</td></tr>
<tr><td>Reference</td><td>Fixed: 3.2
Smart: 2.3</td></tr>
<tr><td>Growth</td><td>Fixed: 3.2
Smart: 3.5</td></tr>
<tr><td>Global</td><td>Fixed: 3.3
Smart: 0.9</td></tr>
<tr><td>Environmental</td><td>Fixed: 3.4
Smart: 5.6</td></tr>
<tr><td>Disruptive</td><td>Fixed (Light): 3.4
Smart (Light): 5.6
Heavy: 1.7</td></tr>
</table></td><td>Consistent with NZGP1 with minor updates.</td></tr>
<tr><td>EV charging smartness</td><td>Not specified</td><td>Smartness by 2050:
<table>
<tr><td>Scenario</td><td>Smartness by 2050 (%)</td></tr>
<tr><td>Reference</td><td>40</td></tr>
<tr><td>Growth</td><td>50</td></tr>
<tr><td>Global</td><td>20</td></tr>
<tr><td>Environmental</td><td>60</td></tr>
<tr><td>Disruptive</td><td>50</td></tr>
</table></td><td>The smartness in all scenarios except the disruptive scenario is consistent with NZGP1. The smartness in the disruptive scenario is set to 50% to better reflect uncertainties in EV charging.</td></tr>
<tr><td>Solar generation</td><td><table>
<tr><td>Scenario</td><td>Generation in 2050 (TWh)</td></tr>
<tr><td>Reference</td><td>2.3</td></tr>
<tr><td>Growth</td><td>2.8</td></tr>
<tr><td>Global</td><td>0.9</td></tr>
<tr><td>Environmental</td><td>4.6</td></tr>
<tr><td>Disruptive</td><td>4.6</td></tr>
</table></td><td><table>
<tr><td>Scenario</td><td>Generation in 2050 (TWh)</td></tr>
<tr><td>Reference</td><td>3.1</td></tr>
<tr><td>Growth</td><td>3.9</td></tr>
<tr><td>Global</td><td>1.1</td></tr>
<tr><td>Environmental</td><td>6.4</td></tr>
<tr><td>Disruptive</td><td>6.4</td></tr>
</table></td><td>Consistent with NZGP1</td></tr>
<tr><td>Residential solar uptake</td><td><table>
<tr><td>Scenario</td><td>Number of 3 kW solar installations in 2050</td></tr>
<tr><td>Reference</td><td>531,620</td></tr>
<tr><td>Growth</td><td>655,330</td></tr>
<tr><td>Global</td><td>190,210</td></tr>
<tr><td>Environmental</td><td>1,076,300</td></tr>
<tr><td>Disruptive</td><td>1,076,300</td></tr>
</table></td><td><table>
<tr><td>Scenario</td><td>Number of 3 kW solar installations in 2050</td></tr>
<tr><td>Reference</td><td>797,420</td></tr>
<tr><td>Growth</td><td>983,000</td></tr>
<tr><td>Global</td><td>285310</td></tr>
<tr><td>Environmental</td><td>1,614,440</td></tr>
<tr><td>Disruptive</td><td>1,614,440</td></tr>
</table></td><td>Consistent with NZGP1</td></tr>
</table>

While not part of the EDGS assumptions, our demand forecasts for this project reflect:

- Updated information on step changes.
- Recent historical demand.
- Updated base peak demand across all scenarios in the USI to be more in line with EDB's GXP level forecasts.

Table 10: Generation variations

<table>
<tr><th>Assumption</th><th>2019 EDGS Value</th><th>Variation from EDGS</th><th>Rationale</th></tr>
<tr><td>Generation stack</td><td>Details in generation stack not specified e.g., capital costs, named projects, capacity factor</td><td>Incorporate information from the 2020 generation stack updates, recent Transpower connection queries and news articles.</td><td>To incorporate newer and more detailed information.</td></tr>
<tr><td>Wind repowering</td><td>Wind repowering not mentioned in EDGS</td><td>Assume that all wind farms are repowered at the end of their 30-year lifetime (with increased capacity), or earlier if indicated by developers.</td><td>Assumption is consistent with those specified in the proposed BBC Assumption Book 2.0.</td></tr>
<tr><td>BESS (batteries)</td><td>Grid scale batteries not mentioned in EDGS</td><td>Include two, four and eight-hour batteries in our generation stack, based on cost information from NREL.</td><td>To add an alternative peaking option. Assumption is consistent with the proposed BBC Assumption Book 2.0.</td></tr>
<tr><td>New generation cost decline</td><td>LRMC changes by 2050 are specified for wind and solar generation.

Solar
<table><tr><td>Scenario</td><td>Change</td></tr><tr><td>Reference</td><td>-50%</td></tr><tr><td>Global</td><td>-50%</td></tr><tr><td>Disruptive</td><td>-45%</td></tr></table>
Wind
<table><tr><td>Scenario</td><td>Change</td></tr><tr><td>Reference</td><td>-13%</td></tr><tr><td>Global</td><td>-7%</td></tr><tr><td>Disruptive</td><td>-27%</td></tr></table></td><td>Use future cost decline scenarios from National Renewable Energy Laboratory's (NREL's) 2023 annual technology baseline (ATB) to scale capital and fixed O&M (FOM) costs of generation stack projects. Wind, solar, geothermal and BESS project costs are scaled and the cost decline is varied by scenario. The change in the costs by 2050 are given in the tables below.

Solar
<table><tr><td></td><td>FOM change</td><td>CAPEX change</td></tr><tr><td>Environmental Disruptive</td><td>52%</td><td>40%</td></tr><tr><td>Reference Growth</td><td>60%</td><td>49%</td></tr><tr><td>Global</td><td>70%</td><td>64%</td></tr></table>
Wind</td><td>Assumption is consistent with the proposed BBC Assumption Book 2.0.</td></tr>
</table>

<table>
<tr><td></td><td></td><td><table><tr><td>Scenario</td><td>FOM change</td><td>CAPEX change</td></tr><tr><td>Environmental Disruptive</td><td>51%</td><td>62%</td></tr><tr><td>Reference Growth</td><td>77%</td><td>68%</td></tr><tr><td>Global</td><td>88%</td><td>81%</td></tr></table></td><td></td></tr>
<tr><td>Geothermal emission</td><td>Not mentioned in EDGS, but provided in 2020 geothermal generation stack.</td><td>Reduce emission rates from geothermal generation stack by 50% in the Growth scenario.</td><td>To account for the potential of CO2 reinjection.</td></tr>
<tr><td>Biofuel</td><td>Not mentioned in EDGS.</td><td>Add biofuel as a potential fuel source in our thermal generation stack</td><td>To add an alternative dry year option.</td></tr>
<tr><td>Long-term carbon price</td><td>NZ$66/t by 2050, except Environmental scenario (NZ$154/t by 2050)</td><td>Use long-term carbon prices from CCC10F[27] i.e., NZ$250/t by 2050 in all scenarios except Environmental. The carbon price from the International Energy Agency's Net Zero Emissions scenario[28] is used for the Environmental scenario.</td><td>Assume long term carbon prices are consistent with net-zero emissions.</td></tr>
</table>

A.2 Assumptions Book variations

Variations to our Assumptions Book are listed below.

- Adjustments have been made to the generation stack such that only well-advanced new generation is built in the USI. See Section 3 of Attachment 6 – Benefit modelling.
- HVDC loss calculations were calculated using the draft Assumption Book 2.0 assumptions about HVDC losses, being those available at the time of modelling set up.
- AC losses for the USI have been adjusted from the approach outlined in the Assumptions Book. See further details in Section 2.2 of Attachment 6 – Benefit modelling.

27 Climate Change Commission.
28 Net Zero Emissions by 2050 Scenario (NZE) – Global Energy and Climate Model – Analysis - IEA

Appendix B: National demand forecasts

Below we present national demand forecasts that are consistent with the model runs we have used to create the USI forecasts.

Figure 14: National peak forecasts, MW

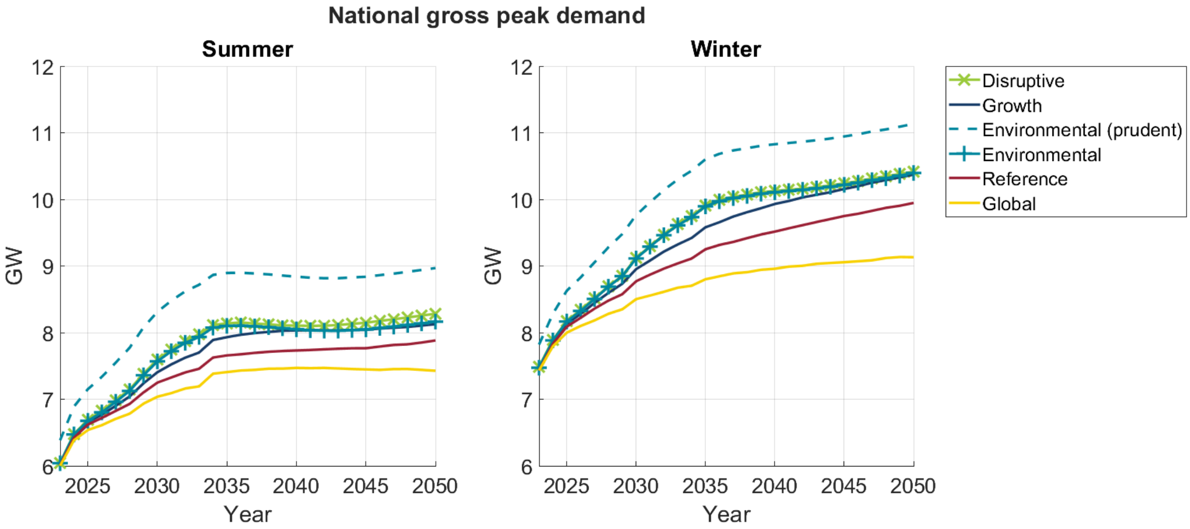
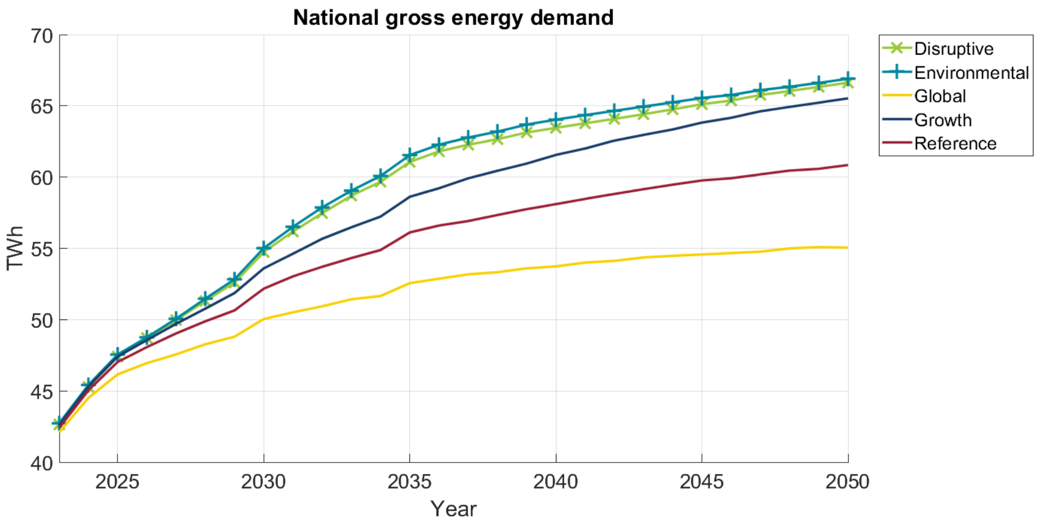


Figure 15: National energy forecasts, TWh per annum



Appendix C GXP Forecasts

Forecasts for each GXP in the USI are provided in the attached spreadsheet:

USI Attachment 1 Appendix C GXP Forecasts.xlsx

The spreadsheet reports the peak demand at each GXP at the time of the GXP peak demand and at the time of the USI regional peak. At the USI regional peak not all GXPs will be at their peak demand reflecting the diversity of demand across the region.

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