Security and Reliability Council

# The risks Transpower manages in relation to its HVDC assets

HVDC extended loss of service: risks, mitigation, response and impact

28 March 2017

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

## 1 The purpose of this paper is for Transpower to explain, in relation to its HVDC assets, what risks it is aware of and how it is managing them

1.1 The Security and Reliability Council (SRC) functions under the Electricity Industry Act 2010 include providing advice to the Electricity Authority (Authority) on the reliability of the power system.

1.2 At its 21 June 2016 meeting, the SRC had an impromptu discussion about the failure of Australia's Bass Strait HVDC link. The SRC subsequently advised the Authority Board on 19 July 2016 that it "…felt that there was a lesson for New Zealand from this event that relates to boundaries of responsibilities and taking account of customers' needs when managing risks."

1.3 The Board discussed the SRC's advice and directed its staff to request Transpower to prepare a report that summarised Transpower's management of HVDC-related risks. The Board asked that Transpower's report be presented to the SRC and the Board's System Operations Committee.

1.4 The purpose of this paper is to present Transpower's report and to obtain any related feedback from SRC members.

1.5 Appendix 4 of Transpower's paper is a placeholder for an insurance-related report that Transpower considers confidential. SRC members will temporarily receive a copy of this appendix during the meeting. SRC members are directed to regard Appendix 4 as confidential.[1]

## 2 Questions for the SRC to consider

2.1 Transpower's report is attached to this cover paper. Representatives from Transpower will attend the SRC's meeting to recap the paper and be available to respond to the SRC's questions.

2.2 The SRC may wish to consider the following questions.

| | |
|---|---|
| **Q1.** | What questions, if any, does the SRC wish to ask of Transpower's representatives? |
| **Q2.** | What further information, if any, does the SRC wish to have provided to it by the secretariat? |
| **Q3.** | What advice, if any, does the SRC wish to provide to the Authority? |

[1] Section 57 of the Crown Entities Act 2004 requires SRC members to not disclose such information.

# HVDC Risk - SRC - 2017

Risks, mitigation, response and impact

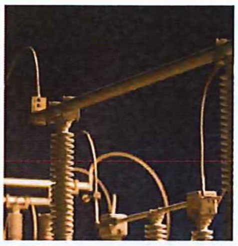
# System Operations

**Transpower New Zealand Limited**

[Report Date]

*Keeping the energy flowing*






TRANSPOWER

| Version | Date | Change |
|---|---|---|
| Draft | 20 Feb 2017 | To the Electricity Authority in draft prior to 28 March SRC |
| V1.0 | 13 Mar 2017 | To the Electricity Authority for 28 March SRC |
| V1.1 | 13 Mar 2017 | To the Electricity Authority for 28 March SRC; confidential Appendix not included |

| | Position | Date |
|---|---|---|
| Prepared by: | Daniel Pringle, Team Leader, System Operations<br><br>Ricky Smith, HVDC and Power Electronics Engineering Manager, Grid Performance | 28 Feb 2017 |
| Approved by: | John Clarke, General Manager System Operations. | 13 Mar 2017 |

## IMPORTANT




**Contact Details**

Address: Transpower New Zealand Ltd
96 The Terrace
PO Box 1021
Wellington
New Zealand

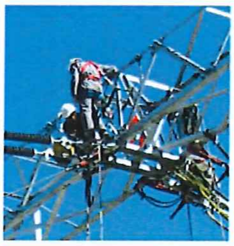
Telephone: +64 4 495 7000

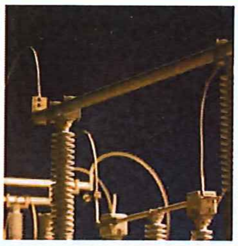
Fax: +64 4 498 2671

Email: system.operator@transpower.co.nz

Website: http://www.systemoperator.co.nz

*Keeping the energy flowing*





TRANSPOWER

Transpower New Zealand Limited The National Grid

# EXECUTIVE SUMMARY

Transpower owns and operates New Zealand's 1,200 MW HVDC link between Benmore in the South Island and Haywards in the North Island. The link features three submarine cables across the Cook Strait configured as two transmission lines known as Pole 2 and Pole 3.

Transpower is comfortable with its awareness, assessment, and mitigation of the risks to the HVDC link. These are risks to manage not eliminate. The HVDC link is physically resilient, with several key advantages over the recently damaged Basslink, including our multi-cable approach and configuration.

The principal albeit very low risks to Transpower's cables are earthquakes and marine vessel cable strike. However there has been no earthquake damage to power cables to date, and only one cable strike, in 1991, which resulted in significant changes to the Cook Strait Cable protection legislation. These risks are managed through a comprehensive plan including contracting for marine patrols, cable testing and repairs. Land-based HVDC assets are physically resilient including the redundancy from physical separation of key Pole 2 and Pole 3 converter equipment.

A sudden total loss of service (bipole failure) may lead to automated under frequency load shedding (AUFLS) dropping customer load without notice to maintain system security. The system operator would then undertake usual system restoration and manage the North Island and South Island as separate power systems. Under the vast majority of circumstances, power will be restored to all customers.

Transpower would look to quickly assess the immediate situation and future outlook, and to convene an industry response group. The impact on security of supply would depend on the time of year, availability of other transmission and generation, and hydrology.

The emergency arrangements available to the system operator to manage a grid emergency or extended emergency apply in an HVDC outage. These include the direction of load control under a grid emergency or rolling outage plan. An extended outage could lead to an Official Conservation Campaign.

The highest immediate risk is the ability to meet peak demand in the North Island. For peak winter loads, demand response or control may be necessary to meet peak load while maintaining real time security objectives. The South Island has no such problem, with a large winter capacity margin. Energy security over an extended outage may depend on hydrology and Transpower would increase its hydro monitoring and risk assessments.



## OUTLINE OF THIS REPORT

This report has three sections: an overview of Transpower's HVDC assets and their risk management; Transpower's immediate and ongoing response to manage the power system should a total HVDC failure occur; and a high level view of the security of supply implications of a total HVDC outage.

The first section includes discussion of the events which could give rise to extended loss of service and total loss of service (bipole failure), and the indicative timeframes to resume service should these events occur.

Setting aside its very low probability, the next two sections consider Transpower's operational response and the security of supply implication should an extended total outage eventuate.

# 1. New Zealand's HVDC Assets and Risk Management

## 1.1 Overview of New Zealand's HVDC link



Transpower owns and operates the 610 km high voltage direct current (HVDC) transmission connection between Benmore in the South Island and Haywards in the lower North Island.

Sometimes referred to as the "Cook Strait cable" there are three in-use power cables connecting Fighting Bay in the South Island to Oteranga Bay on the North Island. Overhead circuits connect these cable stations to the AC-DC converter stations at Benmore and Haywards.

Figures 1 and 2 give an overview of the end-to-end HVDC equipment and the position of the Cook Strait Cable Protection Zone (CPZ) around the power cables and adjacent fibre optic cables between the islands. Typically Pole 2 uses one cable, and Pole 3 uses two cables. Bipole operation refers to having both poles in operation, monopole to only one. A bipole failure means total loss of transfer between the islands.

The HVDC link is offered to the market at up to 1,200 MW for north flow and 850 MW south flow. The new HVDC control systems also provide frequency keeping and reserve sharing functions. A DC outage would therefore affect ancillary services as well as energy transfer.

The flow of energy is predominately northwards, connecting the southern hydro lakes to northern load centres. South flow allows North Island generation to supply the South Island under 'dry' conditions or when it is otherwise economically favourable to do so. See Appendix 1 for power flow across the HVDC link since Pole 3 commissioning.

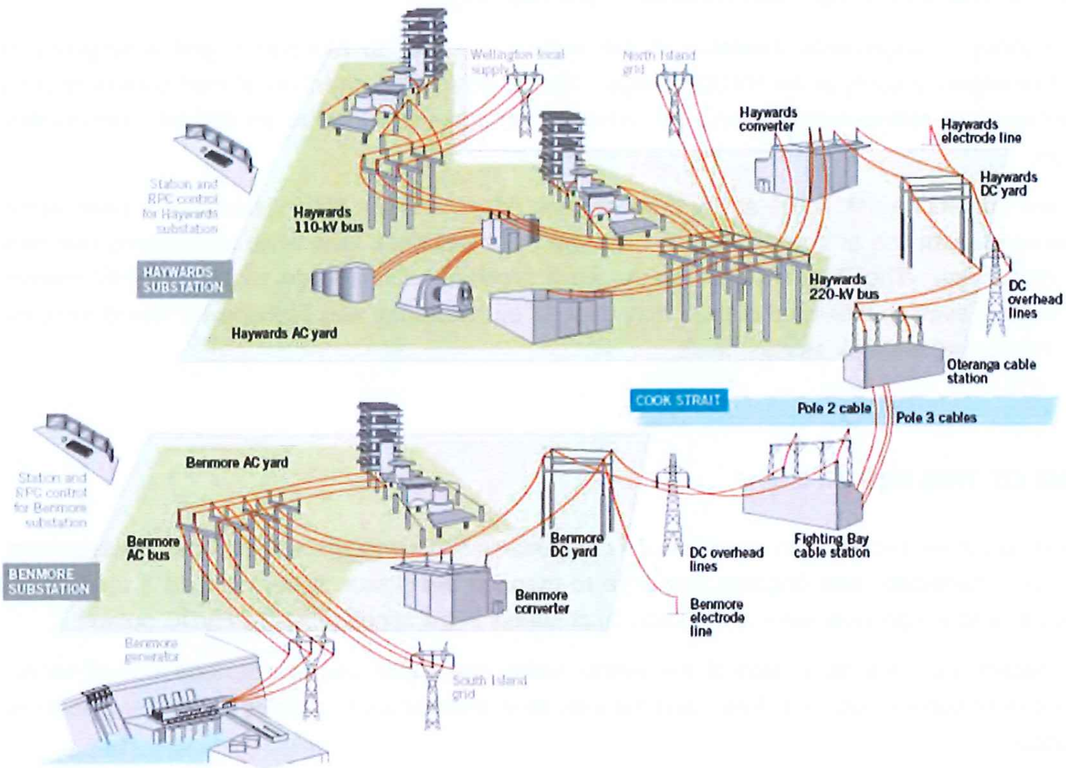



Figure 1. Overview of Transpower's HVDC assets, including Benmore and Haywards converter stations, overhead lines, and submarine cables connecting Fighting Bay and Oteranga Bay cable stations.

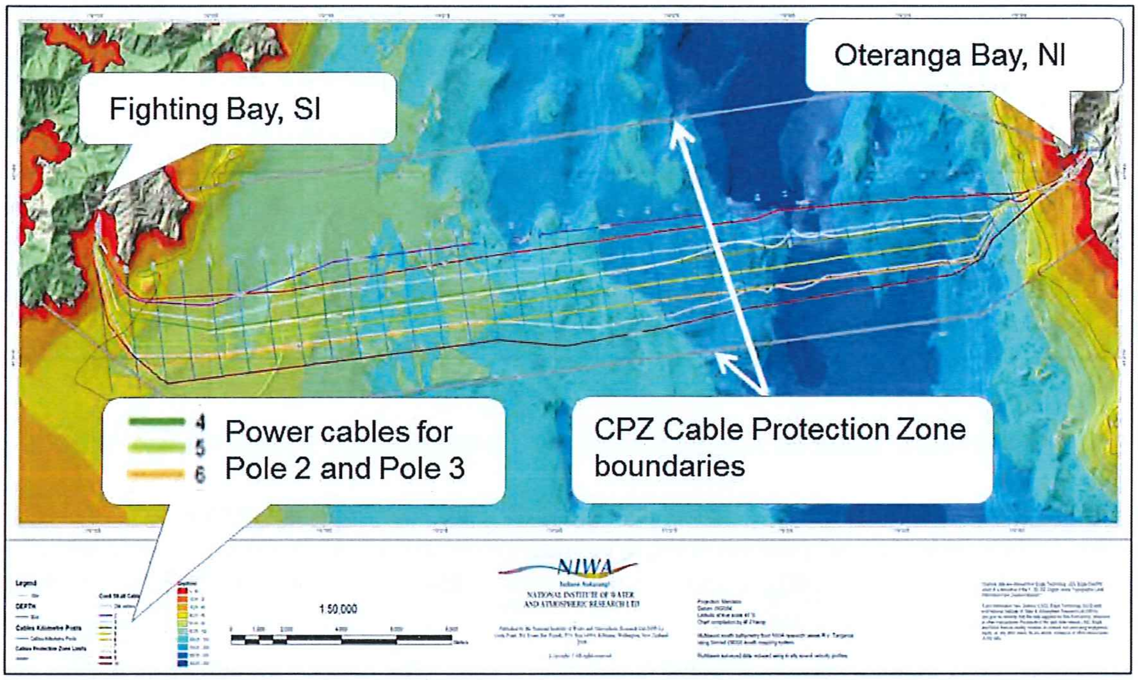



Figure 2. Map of Cook Strait showing legislated Cable Protection Zone and position of fibre optic and power cables. In-use cables (4,5,6) are in the centre of the hatched area.

## 1.2 New Zealand's HVDC assets are physically resilient

Several key attributes make Transpower's HVDC assets physically resilient. We note below important advantages over the Basslink connection between Tasmania and mainland Australia, which failed and was out of service December 2015 – June 2016.

The 290km long undersea section of the Basslink consists of one power cable, one metallic return cable and one fibre optic cable wrapped up as a bundle, laid in a seafloor trench. This monopole system means damage to either the power or metallic return cable renders the link in-operable.

Key advantages of the Transpower submarine cables compared to Basslink:

- Redundancy: Transpower has three separate 500 MW rated submarine cables. While rated at 1,200 MW, transfer is less than 500 MW for about 69% of the time and less than 1,000 MW for more than 99.9% of the time. The system can therefore tolerate the loss of one cable with minimum impact to service, and can accommodate the loss of two cables most of the time.
- Configuration: Transpower's submarine cables are separated by 500-650 m across Cook Strait (reducing to 7m at the cable stations). This separation makes it unlikely that more than one cable would be involved in in an underwater damage event. Transpower uses earth return, rather than a separate cable which could be damaged.
- Short length: New Zealand's submarine cables are about 40 km long, making fault testing and location much easier than for the 290 km Basslink. Fault location and repair was delayed in the Basslink outage because the main fault location test (Time Domain Reflectometry) location has an accuracy of about 1%, or about 3 km for Basslink. Repeated cable raises and cuts were required to find the damaged section.

Transpower also has good quality baseline test results to support fast fault location. Our pre-fault test results give comparison data which further reduces uncertainties in fault finding. Testing is carried out annually with the last testing in November 2016.

- Seafloor position: Transpower cables are on the sea bed enabling relatively easy inspection. The Basslink cable bundle is buried in a seafloor trench. For the recent Basslink location and repair, cable excavation was required which stirred sediments causing delays and difficulties from reduced visibility.

An overview of the Basslink outage, key lessons for Transpower and a detailed comparison of the Basslink and the HVDC are included in Appendices 2 and 3.



## 1.3 THE HVDC ASSETS ARE INCLUDED IN TRANSPOWER'S RISK FRAMEWORKS

Transpower is responsible for the overall management, operation and maintenance of the HVDC assets. This includes regular planned outages for inspections and maintenance, contracting specialist marine patrol and repair capabilities, and maintaining accessible spare plant items including lengths of cables, fittings and temporary towers.

Transpower's risk management of the HVDC assets and operation includes 'bowtie' risk analysis and semi-quantitative risk assessment (SQRA) methods. These frameworks create a view of the risk profile, causal factors, potential modes of failure, control environment and consequences for both our land- and marine-based HVDC assets. This view includes controls to both prevent an event and mitigate the impact.

Risk analyses of the submarine cables, converter stations, cable stations and transmission lines include assessment of the likelihood and consequences of damage associated with the activities of personnel and third parties, natural or environmental hazards, and electrical, mechanical and functional failure.

### Submarine Cables

The recent Basslink failure has heightened interest in risks to our submarine cables. Transpower insures these cables and two adjacent fibre optic cables, and Appendix 4 includes some of the information presented to prospective insurers. Transpower consistently receives good feedback on its risk management from these discussions, and has stable insurance arrangements in place.

The principal – albeit low - risks to these cables are marine vessel strike and earthquake:

- The greatest risk of damage to the cables comes from illegal fishing activities (e.g. cables being struck, snagged or otherwise fouled by trawling nets or anchors.) Since 1991 there has nevertheless been only one strike to a power cable[1].
- Earthquake risk to the cables is considered to be low due to their orientation relative to the seafloor expression of fault lines. There has been no earthquake damage to cables to date, either by the large Christchurch and Kaikoura events, or closer events above 6.0 magnitude.

[1] This was an original cable installed in 1965 which was subsequently decommissioned not repaired. Since 1991 there have also been a number of strikes to the lighter and more susceptible fibre optic cables.

Transpower has in place a range of measures to reduce, or provide early warning of, potential risks that may impact the cables. These include our multi-cable approach, the existence and patrolling of the Cable Protection Zone (CPZ), regular cable monitoring and testing, regular underwater remotely operated vehicle (ROV) and dive surveys, and cable cut, lift and cap capabilities.

Much of this support is provided under contract with Wellington-based Seaworks, whose contracted services include boat patrols in the CPZ, helicopter support of patrols, annual ROV and dive surveys, emergency ROV work, and the management of cable fault response, CPZ signage and survey points.

Transpower is a party to the "Marine Maintenance Service Agreement" (MMSA) in which a consortium of cable owners jointly leases a suitable repair vessel on a full time basis. The contract with ASN, owners of the vessel *Ile de Ré*, expired in February 2017. Coverage for Transpower, Basslink and others will now be provided by the similarly capable vessel *CS Reliance*, under a new contract with TE SubCom.



Concurrent failure of two submarine cables has been assessed at our lowest likelihood rating of 'very rare'. This would still allow monopole operation and transfer of up to 500 MW in either direction. An extended outage of all three cables is even less likely.

## Other HVDC Assets

In addition to the submarine cables, a full picture of the HVDC risks includes the land-based assets. Importantly, land based equipment can be more easily accessed for risk mitigation measures and repairs than the cables.

A large earthquake is again a principal risk, the response to which may be limited by wider damage to major infrastructure.

- Depending on location, a large earthquake (or severe weather event) could result in the need to replace multiple overhead transmission towers. This could result in a total outage of several months to procure and install a large number of towers. Damage to a small number of towers can be handled with a faster interim response using spare temporary poles. These can be installed in weeks rather than months: 4 towers were replaced with temporary poles after a severe wind event, taking about 10 days to erect; and the November 2016 Kaikoura earthquake required one spare temporary tower to be installed, with a planned total HVDC outage of 13 hours' duration about 8 weeks after the quake.
- A tsunami in the Cook Strait could threaten the cable stations at Fighting Bay or Oteranga Bay. These sites include fire isolation and other measures to contain or limit damage, but a tsunami could still prove destructive. Temporary repairs are likely to be possible within a timeframe of several months.

Although very unlikely, a fire in a valve hall at the Benmore or Haywards converter stations could also result in an extended loss of service for one pole. At these sites the AC-DC conversion for Pole 2 and Pole 3 is performed in physically separated buildings. The Pole 3 valve hall is seismic base-isolated and contains no flammable material. We intend to upgrade the Pole 2 equipment to the standard from oil-filled bushings and capacitors in the period 2020-25 (RCP3 regulatory period). Meanwhile, Pole 2 valve hall has fire protection in the form of sprinklers.

## Indicative timeframes for possible loss of service

Given the physical redundancy in the HVDC assets, there are very few, very low probability events which could result in a total loss of service for a time measured in months rather than days or weeks.

These are: concurrent failure of all 3 submarine cables or cable terminations, concurrent damage to multiple convertor transformers (affecting more than one phase), concurrent failure of Pole 2 and Pole 3 thyristor valves, failure of Haywards condensers, earthquake damage to a large number of overhead towers.

The longest duration for prolonged loss of cable availability would arise from events requiring deep-sea repair, or manufacture of replacement cables. This risk is offset by the Seaworks and MMSA contracts, and by storing in Wellington 1.2km and 2.4 km lengths of cable as well as other spares. An indicative time for shallow-water repair comes from the 6-months to repair cable 6 following internal electrical breakdown, October 2004 – March 2005.

10

The expected time for return to some service for these events is less than 6 months for all but the extremely low probability events of multiple subsea cable failures or valve hall failure. Transpower's Annual Security Assessment with its 6-month outlook is therefore well matched to assess the potential security of supply implications of total loss of HVDC transfer.

Overall, we consider that HVDC risks are well understood and managed. Our risk review and analysis process is repeated periodically and reported to the Transpower Board.

# 2. TRANSPOWER RESPONSE TO A PROLONGED LOSS OF HVDC TRANSFER

Transpower's response to an HVDC failure would be managed with the same set of ancillary services, system operation tools and response procedures used to respond to other power system events. These measures apply generally to power system events such as a transmission line trip or generation trip. They are not specific to HVDC events, but they do apply to HVDC events.

The key references here are: the system operator Policy Statement, clauses of the Electricity Industry Participants Code (the Code) relating to grid emergencies, the system operator Emergency Management Policy (EMP) and the System Operator Rolling Outage Plan (SOROP).



## 2.1 OVERVIEW

Should HVDC transfers cease due to an unexpected event then Transpower's first actions are to stabilise the power system and undertake necessary restorations.

If this lead to an extended HVDC bipole outage, it would require operation of the North Island and South Island as separate, self-sufficient power systems. This mode of operation occurs periodically during planned HVDC maintenance outages and presents no problems per se.

Immediately after an event Transpower would continue to maintain the power system with the generation and reserve resources offered into the market, and if necessary call on the emergency arrangements to maintain system stability and security.

If there had been reliance in one island on HVDC transfers from the other island, then this could result in demand control in order to prevent uncontrolled outages. As discussed in the next section, in the vast majority of cases there is sufficient generation to shortly restore load to pre-event levels in both islands.

Transpower would likely convene a crisis management team from across HVDC engineering, grid and system operations. We would seek to identify the cause of the problem and the expected time for return to partial or full service.

In determining how to best respond, we would monitor the outlook for meeting demand peaks and total energy requirements in the North Island and South Island over the expected duration of the outage. We would communicate with and work with industry on appropriate responses particularly to any longer term issues which emerge.

### Response in real time and immediately after an HVDC bipole failure

Within the Policy Statement a bipole failure is deemed an Extended Contingent Event (ECE). This means that instantaneous reserves (IR) are not procured to fully cover the risk of a trip. If the bipole trips at high transfer, then a combination of IR and automatic under frequency load shedding (AUFLS) would be used to stabilise the system. In other words, some consumer load may be shed without notice in order to stabilise the system and prevent frequency falling to the point of cascade failure.

Following the initial response, the system operator restoration procedures would commence. Note that if the bipole were rendered inoperable at low transfer, then IR may be sufficient to stabilise the system without the need for AUFLS and subsequent system restoration.

If an immediate shortfall of capacity is evident in either island, usual operating procedures would be used to manage existing demand and to request additional generation. Warning (WRN) or grid emergency notices (GEN) would be issued to request increased generation offers. Remaining generation shortfall within the affected Island would be managed via direction to distributors and direct connect consumers to limit or manage demand.

Immediately after an event Transpower as grid owner would begin to assess the cause and expected outage duration, and as system operator would begin to assess short term capacity and energy adequacy. If the ability of the power system to meet demand over an extended period of time is at risk, then an extended emergency applies.

## 12 Options for managing an extended emergency situation

The system operator has two primary means to manage emergencies:

- *grid emergencies* – with emergency management policies set out in the Policy Statement. Grid emergency measures can be called on at short notice and enable the system operator to specify capacity limits for specified times, to be met by EDBs and direct connects; and
- *extended emergencies* - described in the EMP, including the use of rolling outages and official conservation campaigns. Implementation of rolling outages includes a planning phase and affords flexibility in how targets are met by EDBs and direct connects. Consumer response to conservation campaigns are voluntary.

The system operator will evaluate whether ongoing grid emergencies or rolling outages would better manage a given situation. The real time load control process is sustainable for as long a period as necessary, or until such time as a rolling outage programme or conservation campaign is established.

If it is evident that an HVDC outage could lead to an energy shortage, and it is clear that there is more than a 50% probability of unplanned outages arising due to an energy shortfall, then Transpower as system operator has discretion to make a supply shortage declaration, after consultation with the Authority, and enact the SOROP.

The SOROP provides for rolling outages as an industry-known means to manage an extended energy shortage in an orderly manner. The SOROP may be applied to any situation when a supply shortage exists due to a power system event, or is threatened via a developing situation.

After the declaration of a supply shortage declaration, the system operator implements rolling outages via direction to distribution companies and direct connect consumers to limit or manage load. This is done in accordance with participant rolling outage plans (PROPS) which these participants must publish and keep current.

Under either a grid emergency or rolling outage situation, distributors and direct connect consumers are called on to shed load. In either case Transpower would monitor the outlook for capacity (MW) and energy (GWh) adequacy, and publish updated hydro risk curves.

The system operator may, on occasion, need to employ both grid emergencies and rolling outages in response to an emergency situation, either sequentially or concurrently.

Should the loss of the HVDC link cause a developing supply shortage, an official conservation campaign (OCC) could be used to mitigate the need for ongoing rolling outages. A conservation campaign would involve considerable media exposure, and ideally ministerial and EECA support to call for voluntary load saving targets. Campaigns in 2001, 2003, and 2008 aimed for 10% load reduction.

The EMP describes the arrangements under which the system operator shall prepare for and commence an OCC, including engagement with the Authority and participants. In general, the threshold for an OCC is that the system operator forecasts the risk of energy shortage to exceed 10% for more than a week.

## 2.2 TRANSPOWER'S CONTRIBUTION IN WIDER INDUSTRY RESPONSE

In addition to the system operator response above, we expect Transpower will quickly convene an industry group to ensure information sharing on the state of the power system. Good communication will be required within the industry and with the wider public.



While no formal arrangements exist for calling an industry group together, or taking the lead, we expect the New Zealand electricity industry to engage constructively should this need arise. This expectation is supported by the way in which the industry has in the past come together to manage significant industry events, including concern over low South Island lake levels in 2008.

We would expect the industry group to consider how transmission assets, generation, loads, and reserve providers could be made available and offered in such manner as to reduce the likelihood or extent of any unserved demand.

Key aspects here would include the supply and demand balance and security of supply outlook for the expected duration of the outage, as well as potential mitigations. These might include the relief of any transmission, generation or other constraints, and potential regulatory intervention to minimise the outage impacts on consumers (for instance, relaxation of some system security-related standards).

# 3. SECURITY OF SUPPLY FOR AN EXTENDED BIPOLE OUTAGE

Given the increasingly important role of the HVDC to share energy and reserves between the islands, an extended bipole outage has clear implications for security of supply – the ability to securely meet customer demand in both islands.

We discuss below the outlook from a high level security of supply analysis. This is primarily based on the system operators Annual Security Assessment methodology with the HVDC 'turned off'. This method considers the winter period 1 April to 30 September, the 6-months of highest peak demand and total energy use. As noted in Section 1 of this report, this duration covers most of the credible scenarios for a bipole outage.



A key general result is that the North Island gets an 'amber light' for winter capacity margin - with demand response or load control potentially required to meet peak demand while still maintaining N-1 security. This picture tightens further with the future exit of Huntly units. The South Island gets a 'green light' with a winter capacity margin of about 1,000 MW.

Over an extended outage, careful monitoring will be necessary as both the South Island and North Island could require load control or emergency measures to withstand a full winter without the HVDC. The North Island is here in a much stronger position due to thermal and geothermal plant. Nevertheless, poor hydrology at the start and early stages of an extended outage could result in need for a conservation campaign, rolling outages, or both, to manage the risk of unplanned outages.

The specific impact of an HVDC outage on security of supply will depend strongly on three factors: the time of year which largely determines peak- and total energy demand, generation plant availability, and hydrology - both initially and over the duration of the outage. The extent of demand side response in the form of load reduction and load-shifting is a key secondary factor.

## 3.1 SECURITY OF SUPPLY ASSESSMENTS

Each year the system operator publishes an Annual Security Assessment (ASA) with a 10-year ahead view of security of supply. Below we show results for the North Island and South Island by re-running the 2017 ASA analysis with the HVDC capacity set to zero.

The two key measures here are winter capacity margin (WCM), the difference between winter peak demand and generation capacity contributions to meeting this peak, and the winter energy margin (WEM) which measures the difference between total energy requirement total available generation over a period of time relative to the total energy use over this time.

These are calculated for 6 different scenarios for the winters of 2017 – 2026. Demand growth over this time is modelled as +1% pa. The base scenario of existing and committed new generation has 2 Huntly Rankine units unavailable from winter 2023, with a clear break in both NI capacity and energy margins between 2022 and 2023. The other scenarios include high, medium and low probability new generation.

The charts below show the winter capacity margin and winter energy margin for these generation scenarios relative to winter demand peak and total energy requirements[2]. In the ASA these margins

---

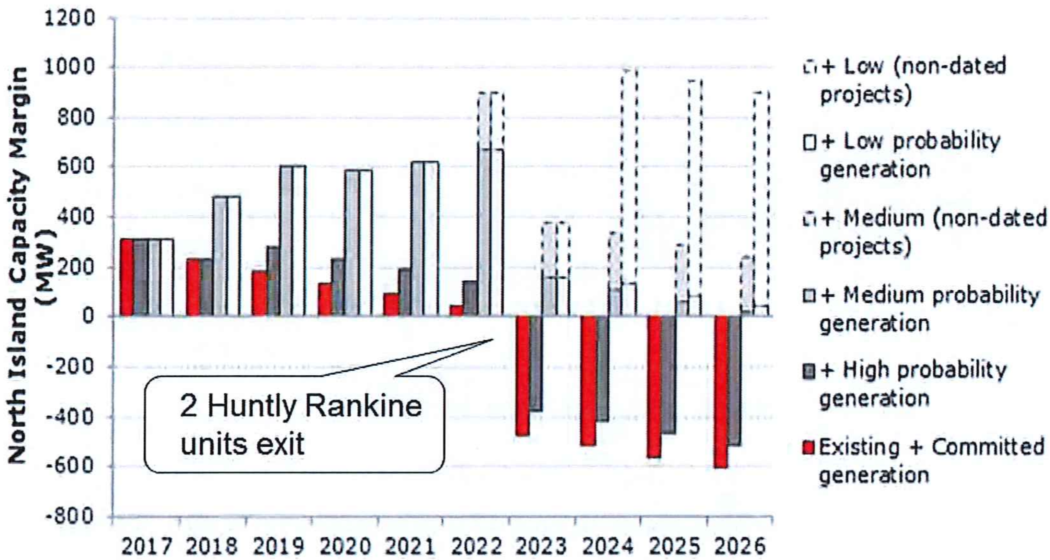
[2] For a full description of the analysis and underlying assumptions, refer to the ASA reports and supporting documents on the Transpower website: https://www.transpower.co.nz/system-operator/security-supply/security-supply-annual-assessment

are compared to 'standards', derived by the Electricity Authority to reflect economically efficient capacity and energy margins. We here consider only the security implications of the margins, not reference to these standards.

## 3.2 North Island Security of Supply



North Island winter capacity in a total HVDC outage is tight. For 2017 this margin is about 300 MW, against a winter peak demand of about 4,300 MW. This margin is less than reserve requirements for a CCGT, implying that N-1 security might not be possible without some load control. This margin tightens in future winters with expected demand growth, and becomes negative with the exit of Huntly




Rankine units.

Figure 3. North Island winter capacity margin using early 2017 ASA analysis with no HVDC transfer.

The National Winter Group analysis gives another view of capacity margins, accounting for line losses, intra-period demand peaks (instantaneous demand peaks above the trading period average demand) and reserve requirements. Applying the 2016 NWG analysis with zero HVDC transfer, shows that for the vast majority of the time there is sufficient North Island generation to meet pre-event load. By season it shows:

- No problem for 7 months of the year: for October through April North Island installed capacity and p10 wind generation3 exceeds peak load including requirements for reserves.
- Almost no problem for shoulder months May and September, there are 1 or 2 trading periods a month where the margin is positive but less than reserve requirements.
- Daily peak concerns for winter months June, July, August, for which there are 1 or 2 trading periods each day which could not be met even if reserve requirements are relaxed.

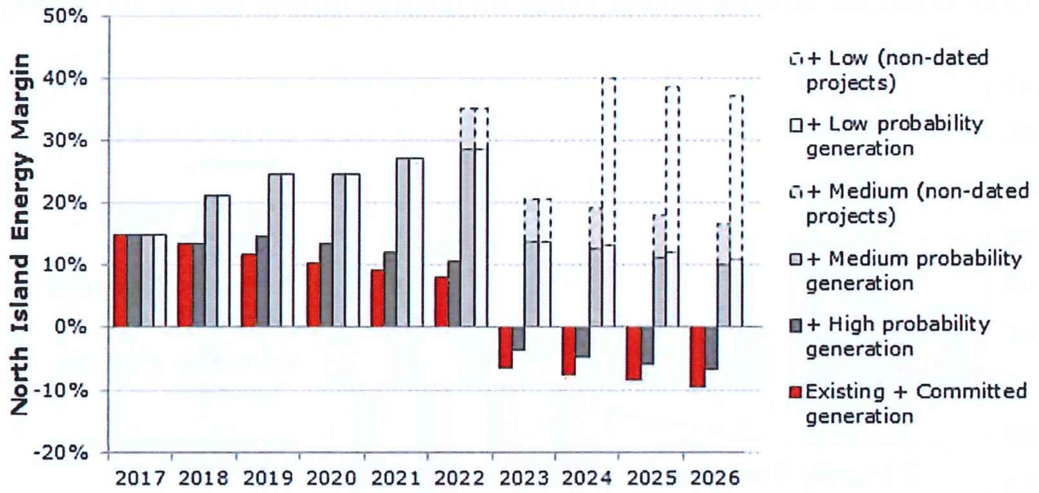
The final point here is a more conservative conclusion than the ASA analysis above. This reflects the more conservative assumptions around demand peaks and generation contribution to peaks in the

[3]The level of wind generation which is exceeded 90% of the time at times of peak demand.

NWG analysis compared to the ASA analysis. These differences reflect the slightly different perspective of these approaches: the ASA assesses generation capability against standards determined on an economic basis, whereas the NWG takes a probabilistic approach to meeting peak loads[4].

Nevertheless, the key point here is that for the vast majority of trading periods in the year, demand can be met by the generation within each island.

Figure 4 shows the North Island winter energy margin (NI WEM) results. The total North Island winter energy requirement is about 14,000 GWh, with a NI WEM for 2017 of about 15%, or 2,000 GWh. Like




the WCM, the WEM also becomes negative on Huntly exit.

Figure 4. North Island winter energy margin using 2017 ASA analysis with no HVDC transfer.

It is important to note that this is a total view over the whole winter. Over this period NI hydro contributes 3,700 GWh, but not captured here is the timing risk from poor autumn and early winter hydrology. In the North Island this risk is significantly offset by thermal and geothermal plant. In practise, voluntary and contracted demand response from large users may very well result under tight market conditions.

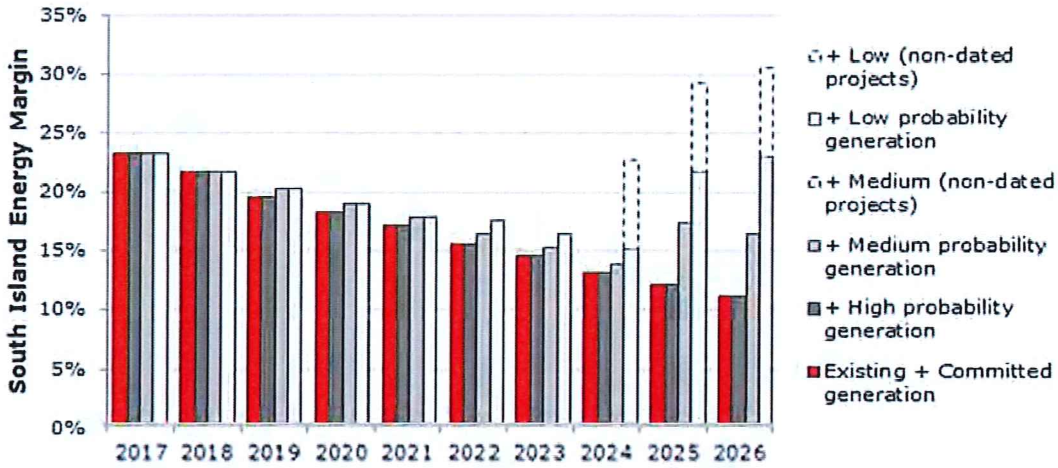
## 3.3 South Island Security of Supply

[4] The distribution of generation availability reflects the uncertainty of wind and run-of-river generation. Regression analysis of the observed demand from the last 10 years has been used to forecast the distribution of possible demand.

South Island winter capacity margin is above 50% at about 1,200 MW. The ASA analysis with no HVDC shows SI hydro (and a little wind) contributing 3,400 MW towards peak loads of 2,200 MW.

Figure 5. South Island capacity margin using 2017 ASA analysis and zero HVDC transfer.

Figure 5 shows this margin above 1,000 MW for the next decade. Forecast demand growth erodes it gradually, with potential uplift from low-probability new generation from 2024. Should Tiwai exit it would further increase this margin through a demand reduction of 570 MW. Huntly exit does not




affect it.



Note that if the HVDC outage was the result of a large earthquake then SI generation may also be affected if dams or other equipment are damaged or requiring assessment.

The South Island total winter energy requirement is about 8,000 GWh. For mean hydrology this is exceeded by about 23% or 1,800 GWh. Key factors in the future outlook are the same as those affecting the SI capacity margin above.

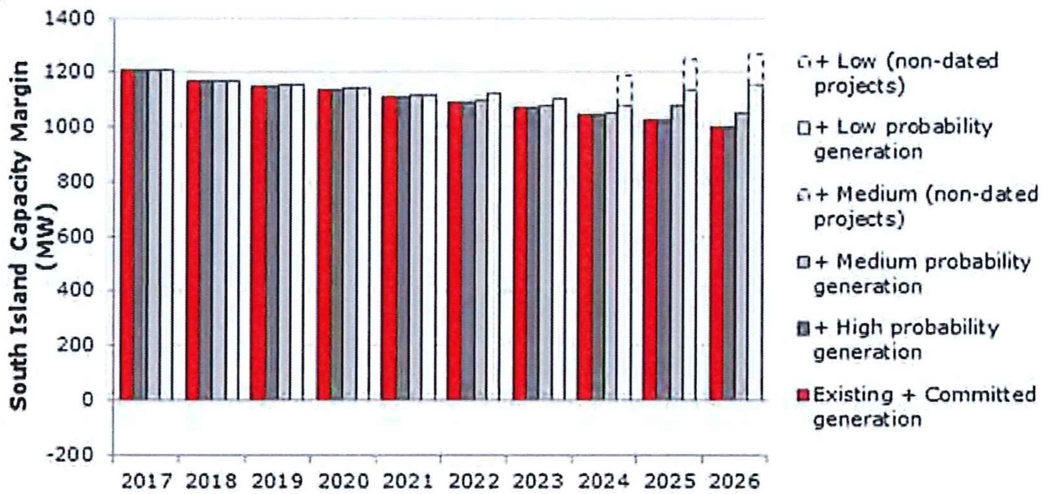



Figure 6. South Island energy margin using 2017 ASA analysis and zero HVDC transfer.

As with the North Island, while this 6-month view may indicate sufficient inflows to meet the total winter energy requirements, low storage and low inflows levels early in an extended outage may result in a developing energy shortage.

The consequences of poor hydrology are worse in the South Island given the absence of thermal or geothermal generation. There would be increased attention on hydro risk curve assessments and reporting.

Although to put this in context, southwards HVDC transfer in autumn 2014 and 2015, essentially to conserve South Island water for the winter, was 105 GWh and 91 GWh respectively, or a little over 2 days' South Island demand.

# Appendix 1: HVDC TRANSFER SINCE POLE 3 COMMISSIONING MAY 2013 TO OCTOBER 2016



Pole 3 was commissioned 30 May 2013. In the nearly three and a half years to October 2016, the average annual transfer was about 2,700 GWh pa Northwards and 110 GWh Southwards. This equates to about 11% of total North Island energy (c. 24 TWh p.a.) and 1% of total South Island energy (c. 15 TWh p.a. of which 5 TWh is Tiwai).

North flow is generally in response to seasonal peak demand – highest in winter and lowest in summer. South flow is generally driven by South Island hydro storage, with potential for high south flows in autumn to conserve South Island water for winter.

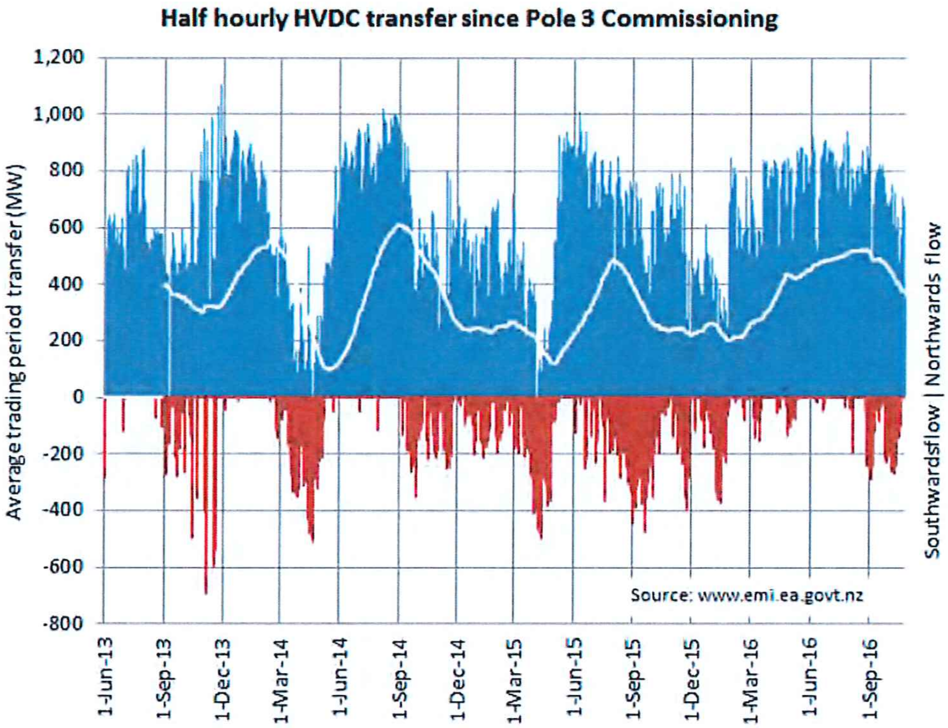



Figure 7. Half hourly HVDC transfer since Pole 3 commissioning, 30 May 2013 – October 2016.

| SEASON | TOTAL TRANSFER, GWh | | AVE. DIRECTIONAL FLOW, MW | | PEAK FLOW, MW | |
|---|---|---|---|---|---|---|
| | North flow | South flow | North flow | South flow | North flow | South flow |
| Winter 2013 | 873 | -4 | 398 | -2 | 879 | -281 |
| Spring 2013 | 755 | -18 | 344 | -8 | 1,110 | -694 |
| Summer 13/14 | 437 | 0 | 199 | 0 | 945 | -41 |
| Autumn 2014 | 401 | -105 | 183 | -48 | 858 | -507 |
| Winter 2014 | 1,345 | 0 | 614 | 0 | 1,022 | -116 |
| Spring 2014 | 604 | -29 | 276 | -13 | 936 | -347 |
| Summer 14/15 | 218 | -2 | 100 | -1 | 678 | -203 |
| Autumn 2015 | 576 | -91 | 263 | -41 | 939 | -493 |
| Winter 2015 | 898 | -24 | 410 | -11 | 1,011 | -364 |
| Spring 2015 | 556 | -68 | 254 | -31 | 795 | -476 |
| Summer 15/16 | 184 | -2 | 84 | -1 | 610 | -172 |
| Autumn 2016 | 1,003 | -3 | 458 | -2 | 884 | -152 |
| Winter 2016 | 1,144 | -3 | 522 | -1 | 946 | -237 |

Table 1. Summary statistics HVDC transfer since Pole 3 commissioning, May 2013 to October 2016. Here Winter = Jun – Aug; Spring = Sep - Nov; Summer = Dec – Feb; Autumn = Mar- May.

# Appendix 2: THE BASSLINK FAILURE AND REPAIR

The Basslink cable fault failure occurred on 20 December 2015 off the Tasmanian coastline. The fault location was 90.5 km from the Tasmanian coast and repairs required a cable cut 1,150 m from the fault.

The cable repair ship *Il de Re* was used for cable repair[5]. This is the same ship Transpower has available through its own regional services agreement for undertaking a 'lift, cut and cap' of an HVDC power cable in the event of a submarine cable fault.

*Il de Re* is principally designed to undertake submarine communication cable operations, so significant modifications/additions were required prior to its dispatch to undertake the repair of the heavier Basslink cable bundle. It proved necessary to make further adjustments as the initial fault location and eventual repair/jointing process unfolded.



Fault finding included more than 20 ROV dives, jetting of trenches to expose cable and extensive undersea video Time Domain Reflectometry (TDR) and other testing of the cable to locate the fault.

The cut and cap operation was expected to take about 2 weeks once the fault location was identified. The fault was located on 30 March and a cut and cap operation completed. The cable fault was clearly visible when landed on the ship:

Figure 8. Damaged Basslink cable, 2016. The exact cause of the damage is still being contested as of in February 2017. (Photo provided by Basslink to news media.)

Approximately 100m of cable each side of the fault position had to be cut to get to dry cable suitable for jointing. The ship returned to Geelong for modifications, unload 84 tonnes of damaged cable and load the first section of spare cable. On 25 April the first joint was completed and 1,355m of new cable laid. Each joint required at least 6 clear weather days to complete. During the repair there were 20 days lost to poor weather conditions between the completion of the first and second joints.

---

[5]The contract with ASN, owners of the vessel *Il de Re*, expired in February 2017. Coverage for Transpower, Basslink and others will now be provided by the similarly capable vessel *CS Reliance*, under a new contract with TE SubCom.

The link returned to service 13 June 2016. In total, three joints were required and two sections of cable required.

Tasmania peak demand is about 1,300 MW in summer and 1,900 MW in winter, of which 60% comes from 20 large users. with the Basslink rated at 500 MW. Unavailability of the Basslink meant:

- Tasmania TEMCO manganese alloy facility was obliged to reduce power consumption by 30 MW
- Agreements with three major industrial customers were reached for load to be reduced by a combined 180 MW
- The previously de-commissioned gas-fired Tamar Valley station was returned to service
- Up to 200 MW of portable diesel generators were deployed (though not required for operation, as timely rainfall allowed hydro generation to be brought back on line.)
- An economic cost estimated at in excess of $AUD500M.
- Political fallout, including enquiries into hydro management and merchant generation sales (via export over Basslink to mainland Australia) by Hydro Tasmania, a state owned generator.

References and links:

http://www.dpac.tas.gov.au/__data/assets/pdf_file/0017/141803/Tasmania_s_Energy_Sector_-_an_Overview.PDF

http://www.aph.gov.au/Parliamentary_Business/Committees/Senate/Scrutiny_of_Government_Budget_Measures/Budget_Measures/Fourth%20Interim%20Report/c01

http://www.theaustralian.com.au/news/inquirer/fighting-to-keep-tasmanias-lights-on-in-energy-crisis/news-story/38e96f65902d08f1e894bd0d42d29377

## Lessons for Transpower from the Basslink failure

Key lessons from the Basslink outage for Transpower were in emphasising the benefits of our multi-cable approach and configuration, the value of good cable testing and the potential difficulties of deep sea cable repair.

Configuration

- the benefits of Transpower's existing bipole configuration and cable redundancy
- advantages for handling of a single cable in New Zealand (vs. the Basslink bundle) and cable laid on seabed (compared to trenching) in a repair scenario

Maintenance

- the importance of the cable owner having accurate cable test results and undertaking baseline testing (without waiting for an obvious cause or external fault to occur)

Repairs

- the criticality of the location of first cut to be within available spare cable length (+ bight length) from fault
- reliance on weather and sea conditions for cable repair operations
- the benefits of having local service agreement and capability for support services in such an event (Transpower's long term relationship with Seaworks).

# Appendix 3: BASSLINK VS. TRANSPOWER HVDC – A COMPARISON OF CONFIGURATIONS, RISKS AND MITIGATIONS



**Key:**

| Lower Risk Factor | | | Higher Risk Factor |
|---|---|---|---|

| **Aspect** | **Basslink – Bass Strait** | **Transpower – Cook Strait** | **Comments/Impact** |
|---|---|---|---|
| HVDC Link Configuration | HVDC Monopole<br>400 kV DC / 500 MW<br>Dedicated Metallic Return (DMR) only | HVDC Bipole<br>350 kV DC / 1,200 MW<br>Ground return (SI land + NI sea electrodes)<br>Optional station ground return (reduced capacity if monopole) | HVDC line commutated converters.<br>Basslink has no redundancy in HVDC configuration. |
| Cable Configuration | Subsea cable bundle consisting of 1x 500 MW HVDC cable, 1xDMR cable, fibre optic cable | 3x separate 500 MW HVDC cables with ~600 m physical separation within legislated Cable Protection Zone (CPZ) | TP's cable #5 ("3rd cable") is configurable to Pole 2 or Pole 3.<br>Loss of one cable can still operate bipole, capacity reduced to 1,000 MW (And currently above 1,000 MW only 0.03% of time so little impact.)<br>If lose two cables can still operate with 500 MW monopole.<br>Basslink cable bundle more difficult to handle for cut and cap and repair operations |
| Subsea Cable Length (per cable) | 290 km | 38 km | Shorter subsea cable in NZ provides more accurate and faster fault location |
| Laying method | Trenched into seabed | On seabed, partial natural burial | Basslink trenching reduces chance of external damage, at cost of more difficult condition monitoring, fault location and repair |

| Aspect | Basslink – Bass Strait | Transpower – Cook Strait | Comments/Impact |
|---|---|---|---|
| Laying Depth | ~80m depth | Up to 200m depth | Fault at greater depth can increase difficulty to locate and repair |
| Prevailing tidal conditions | Small tidal flows | Strong tidal flows | Increased susceptibility to weather events and difficulty for locate and repair activities<br>Remotely Operated Vehicles (ROV) dives are shorter but more of them |
| Baseline cable characteristic testing | Factory test results<br>Time Domain Reflectometry (TDR) | Factory test results<br>TDR – annual<br>Line Impedance Resonance Analysis (LIRA) | TDR typically has 1% accuracy for fault locating: NZ HVDC +/- ~ 200m whereas Basslink +/- ~1,500 m |
| Spare cable holdings | 2 x spare lengths + jointing kits | 2 x spare lengths + jointing kits | Both have spares considered sufficient for typical cable faults |
| Local cable Service Contract | Not aware of any | Yes | Seaworks can provide ROV and support which could significantly reduce delays in initial response, fault location, and repair operation |
| Cut & Cap Vessel Available | Yes | Yes | Part of same group that contracts for subsea cable cut & cap capability. If not available, then a vessel of opportunity may be required. |
| Repair Vessel | Yes | No | Basslink contract with TE SubCom has provision for cable repair within 60 days' window. Vessel of opportunity required if duration longer<br>For TP Vessel of opportunity required |
| Cable Protection by Law | Legal framework in place (Schedule 3A of Telecommunications Act 1997) but only a Voluntary Code of Conduct is in place in Bass Strait | Cable Protection Zone established under the Submarine Cables and Pipelines Protection Act 1996 | CPZ legislation is enforced through contract to patrol CPZ |

# Appendix 4: SUMMARY OF TRANSPOWER 2016 PRESENTATION TO CABLE INSURERS (CONFIDENTIAL)



Confidential Content not included in this report