TRANSPOWER

RCP2 Project Overview Document

Project:	**Islington Spare Transformer Switchgear**
Expenditure Class:	**Base Capex**
Expenditure Category:	**Grid – Enhancement & Development**
As at date:	**June 2014**

Expenditure Forecast *Real 2012/13 NZ$ (m)*	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	**Total**
CAPEX (Otahuhu)		0.54				**0.54**

Need Identification	
Describe the reason for proposing a project (i.e. **need or trigger**)	This project will install an SPS at Islington to provide flexibility for managing outages of 220/66 kV transformers at Islington. Following the tripping of an in-service unit and consequent overloading of the remaining transformers, the SPS will automatically reconfigure the system and/or trip load to keep the loading on the remaining transformers within the acceptable range, avoiding the need for pre-event load management. Islington has three 220/66 kV transformers (two 200 MVA and one 250 MVA) supplying the North Canterbury and Christchurch load. When one of the transformers is out of service, a large amount of load is placed on N security[1]. The two 200 MVA interconnecting transformers (T3 and T7) are old[2] and need to be taken out of service for maintenance with increasing frequency and for longer periods of time. T3 and T7 have a short term (24 hour) contingency rating of 252/256 MVA (summer/winter) and T6 (the 250 MVA transformer) has a short term contingency rating of 297/310 MVA (summer/winter). This means that a significant portion of the North Canterbury and Christchurch load (potentially up to 200 MW) would be at risk should an interconnecting transformer trip while another transformer is out of service. To minimise the impact of a transformer tripping during maintenance of another unit, we have limited maintenance outages of the Islington interconnecting transformers to the summer months (December to March) when the North Canterbury and Christchurch load is low. During outages of an Islington interconnecting transformer, system splits are put in place to manage the consequences of a subsequent outage. The system splits are: • opening the Coleridge–Otira circuits at Coleridge, placing the West Coast (around 20 MW of demand) on 'N' security;

[1] The combined North Canterbury and Christchurch 66 kV load is 450 MW in 2014 and forecast to rise to 540 MW in 2028

[2] Islington 220/66 kV transformers, T3 and T7, are made up of single-phase units and are more than 40 years old. They are scheduled for replacement around 2022-2023.

- opening the Islington–Southbrook circuits; and
- splitting the Islington 66 kV bus with one interconnector supplying the Papanui and Springston loads (100 MW) and the other in-service interconnecting transformer supplying the Addington and Middleton loads (130 MW).

Load can also be transferred from Islington 66 kV to Bromley.

The number of days available for the outages is declining as the North Canterbury and Christchurch load increases (See Figure 1 below).

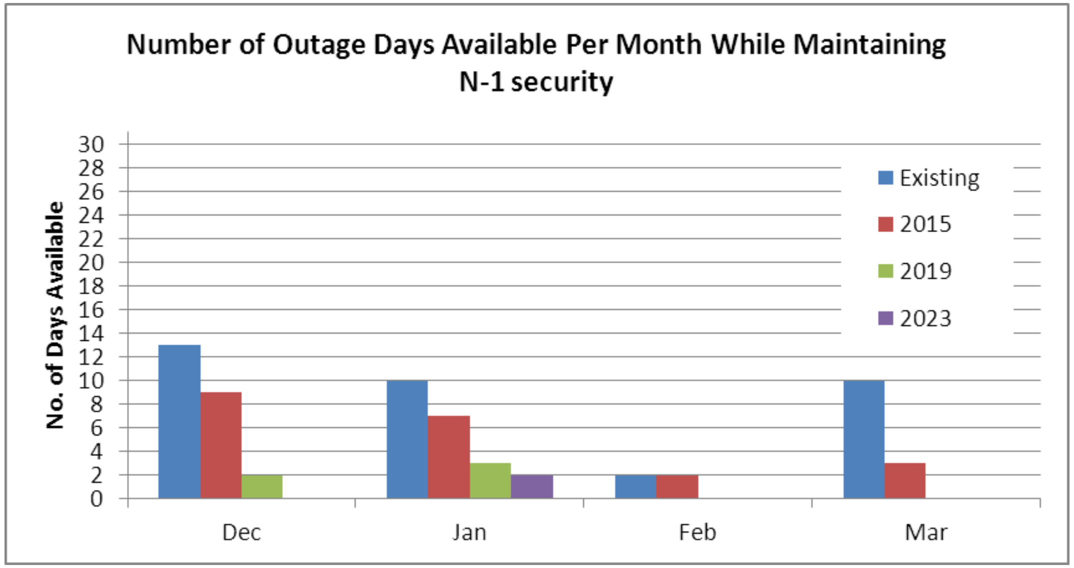

Figure 1: Available outage days for the Islington interconnecting transformers

If one of the three Islington interconnecting transformers should fail it will take a certain amount of time to replace the failed unit with a spare transformer:

- *Failure of one single phase unit of T3 or T7*. If a single phase unit of either transformer fails it will take several days to place the spare single-phase unit into service. If more than one single phase unit fails then it will take four weeks to put the new three phase spare unit into service.
- *Failure of T6 (or T3 and T7 following their replacement with three phase units in the mid 2020s)*. A failure of a three phase transformer will require four weeks to install the system spare.

The outage of one interconnecting transformer means that up to 200 MW of Canterbury load will be at risk following system splits (see above) being put in place to manage the risk of a second transformer outage.

	A high level preliminary economic assessment gave an indicative NPV cost of lost load saved over 20 years with this project of around $1.07m[3]. This assessment assumes: • the probability of a double contingency (one transformer out of service due to planned or unplanned outage and another one fails) between December and March is 0.0053, and • the possibility of a double contingency (both unplanned outages) between April and November is 0.0079 (based on the age and condition of T3 and T7). The unplanned outage probabilities for the Islington transformers are calculated using historic unplanned outage[4] data for the three transformer units at Islington. As the cost of the SPS is less than the NPV benefit we believe the investment is appropriate. We have discussed this project with Orion who have indicated their support[5] for this project.
What is the **timing** of the need and the **confidence level** that issue(s) will eventuate	The project would be completed in 2016. We are highly confident the project will proceed.
Generic assumptions underpinning the need – including any modelling used	DigSilent version 14.1.3 was used in this study. Planning assumptions included the following: • the Annual Planning Report (APR) 2013 demand forecast (prudent regional peak demand). See AM09 - APR 2013, Chapter 4 for the demand forecast methodology; • no new generation is connected in the Canterbury region apart from those that are already committed. See AM09 - APR 2013, Chapter 5 for the generation assumptions; and • various Coleridge generation dispatch scenarios.

3 Assuming average unplanned outage duration of 4 hours, a discount rate of 7 % and VOLL of $20,000 MWh.

4 Unplanned outages on a transformer is usually caused by failure of the transformer or equipment on the transformer branch e.g. HV/LV breakers, Instrument transformers, feeder cables, protection. Due to the age and condition of T3 and T7, these transformers have a higher than historical average unplanned outage rate.

5 Email from Glenn Coates (Orion) to Graeme Ancell (Transpower), "RE: Islington spare transmission energisation", sent 19/3/2014.

Long list of options and high level assessment								
Option Type	**Option**	**Fit**	**Feasible**	**Practical**	**GEIP**	**Security**	**Cost**	**Short list**
Demand side	a) Demand response (DR)	✓	✓	✓	✓	✓	✓	✓
Supply side	b) New generation in the Canterbury region	✓	✓	✓	✓	✓	✗	✗
	c) Generation grid support contract	✗						✗
Transmission options	d) Special Protection Scheme (SPS)	✓	✓	✓	✓	✓	✓	✓
	e) Operation with system spare installed and energised	✓	✓	✓	✓	✓	✗	✓
	f) System Operator intervention/operational measures	✓	✓	✓	✓	✓	✓	✓

- Fit for purpose – will meet the transmission need.
- Technical feasibility – complexity of solution; reliability, availability and maintainability of the solution; future flexibility – Grid Development Strategy.
- Practicality of implementation – Solution implementable by required date (probability of proceeding); property and environmental risks; implementation risks.
- Good electricity industry practice (GEIP) – consistent with good international practice; ensure safety and environmental protection; accounts for relative size, duty, age and technological status.
- System security (additional benefit resulting from an economic investment) – improved system security; system operator benefits (controllability); Dynamic benefits (modulation features and improved system stability).
- Indicative cost – whether an option will clearly be more expensive than another option with similar or greater benefits.

Short list of options	
Option 1 – Do Nothing/System Operator intervention	'Do-nothing' – no network enhancement. System Operator manages transformer loading by implementing pre-contingency system splits and/or constraining on Coleridge generation to manage the post-contingency overload issue.
Option 2 – SPS	This option involves installing a SPS to reconfigure the grid and/or shed load post contingency.
Option 3 – DR	Non-transmission alternatives such as demand response at Islington, Springston, Addington, Papanui.

P50 option costs	
Brief description of the approach used to estimate capex, and, if applicable, opex	A desk-top assessment of a high level scope and building block cost is used to estimate the cost for each option and determine the preferred option. The cost of the preferred option has been substituted with a detailed site specific estimate. The approach and key assumptions used to compile the preferred option estimate are: • the project scope and likely location of the new assets have been determined from a desktop review of aerial photographs, site layout drawings, underground services drawings, and available cable ducts; • the scope assessments have been used to estimate materials and work quantities;

	• the component costs for material and work quantities have been taken from TEES (US cost) • material and plant costs have been determined with reference to period supply contracts currently in place and historic installation costs respectively; • civil and earthworks costs have been extrapolated from historic costs; and • installation costs are informed by similar historic projects and or current quotes from service providers and applied based on the requirements of the site. The total project cost is consistent with historic costs for similar types of projects completed in the past.
Option 1 – Do Nothing/System Operator intervention	$1.07m NPV cost to consumers in terms of reduced reliability. No capital investment is required.
Option 2 – SPS	$500k. This is higher than the default SPS cost of $300k, as it is assumed the SPS would reconfigure the grid at remote sites or trip selected load within the distribution network rather than tripping 'substations' supplied from Islington (e.g. tripping all of Papanui, Addington or Springston). This also assumes the communication infrastructure is available (not included in the cost).
Option 3 – DR	The cost of DR is incurred when it is called upon during maintenance outages. We estimate that the cost will be in the range $500-5000 per MWh. If we assume 8 hours of planned outage per year and the need to reduce load during the outage by 50 MW, then the annual cost of DR will be $200k to $2000k. This option will be considered further as part of the BC2 investigation.

Net benefits and outputs	
Option 1 – Do Nothing/System Operator intervention	Reference case.
Option 2– SPS	Reduces the need for pre-contingency measures such as load management, system splits and generation constrained on. (Cost savings of $1.07m NPV from avoiding lost load.)
Option 3 – DR	Reduces the need for pre-contingency measures such as load management, system splits and generation constrained on. (Cost savings of $1.07m NPV from avoiding lost load.)

Option risk assessment	
Option 1 – Do Nothing/System Operator intervention	• Pre contingency system splits provide only a small improvement on the availability of outage days. • Maintenance outages require increasing amounts of load management over time.

Option 2 – SPS	• Cost variation: Higher cost if communication infrastructure upgrade is required for an SPS to function effectively. SPS can be complicated and difficult to coordinate with other protection which will increase the project cost. • Dependence on third party agreement to manage demand through SPS. There is no certainty around long term agreement for the operation of the SPS.
Option 3 – DR	• Dependence on third party provision of DR – there is limited certainty around provision and cost of DR in the long term. • DR is in the early stages of development: it is not certain that suitable DR will be available on the 66 kV network in the short term.

Preferred option(s)	
What is the currently preferred option / sequence of options / or short-listed options?	Option 2 – Install an SPS
Set out the reasons for choosing the preferred **option(s)**.	This option provides a net benefit and has a cost that is highly likely to be less than that of option 3 (DR).
List key **assumptions** used in determining the preferred option(s).	The generation, demand and cost estimation assumptions used in determining the preferred option are as set out in the preceding sections.
List any **interdependencies** which the preferred option is reliant upon for a successful outcome.	The interdependencies will be identified as part of BC2 detailed investigation phase when preferred solution is identified.

Steps to completion	
What are the next step(s) in choosing the solution	In accordance with our business case process (as described in section 3.6.1 of our AM03 - Planning Lifecycle Strategy) the next steps will be to: • carry out a detailed investigation (BC2) to formally select the preferred option; and • obtain internal approval to proceed with the project (BC3).

When did / will the steps in the internal approval process occur / take place and where were / will they be documented and described	We will follow the following processes for preparing investment proposals. • conduct BC2 investigation to confirm the preferred option in Q3 2014; • complete the consultation with affected stakeholders in Q4 2014; • submit the preferred solution for approval in Q2 2015; • complete the BC3 for project execution in Q4 2015; and • expected commissioning date – 2016.
Identify the key services and assets that will need to be procured to complete the preferred option	Based on the preferred solution identified at this stage, key assets required will be circuit breakers, protection and neutral earthing for the spare transformer, together with associated civil and foundation works. We expect to outsource the detailed design services for the preferred solution. In accordance with our Procurement Policy, we will ensure that a robust and auditable purchase decision-making process is followed. We will complete a Procurement Plan to document the procurement process and for audit purposes. The plan helps us plan for the external procurement of goods and services in a way that ensures we are making the most appropriate purchasing decision for our stakeholders and ourselves.
Identify the key delivery risks	• Projects not properly scoped can lead to cost overruns and not meeting deadlines. During the planning process, we will ensure that project scope is adequately defined and can be implemented within the required timeframe and cost. • We will ensure the project is designed to its specification, the appropriate design reviews are conducted and where necessary, detailed factory inspections are carried out to manage risks. • In the process of procurement, it is essential that we select a supplier that is able to consistently meet quality requirements. Quality must not be compromised in favour of other factors because of the critical influence of quality on risk to safety and the network. • If applicable, we will standardise specifications and procurement of primary equipment to limit diversity and increase inter-changeability. This also allows procurement efficiencies to be attained. • Safety is paramount, the design of all equipment installed must be safe to operate and maintain without compromising performance. Vendors are selected with great care to ensure safe installation and commissioning work and full compliance with all our safety requirements and expectations. • All works required on site will be carried out in full compliance with all of our safety requirements and expectations.

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Supporting Documents and Models	
List of all relevant documents (including relevant policies and consultant reports) taken into account in estimating project costs and describing anticipated deliverability.	Internal Power System Planning memo, “ISL 220/66 kV interconnector outage options”, 15/9/11. AM09 - Annual Planning Report 2013: Chapter 4, Demand Forecast Methodology Chapter 5, Generation Assumptions AM03 - Planning Lifecycle Strategy
Provide a schedule of any models used (including descriptions of model operation and scope).	DigSilent version 14.1.3