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RCP2 Project Overview Document

Project:	**North Taranaki Transmission Capacity**
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	2020-2021	**Total**
CAPEX		4.23	9.45				**13.68**

Need Identification

Describe the reason for proposing a project (i.e. **need or trigger**)	At the time of our December expenditure proposal, this project involved installation of a new 200 MVA transformer at Stratford to increase transmission capacity to meet demand in North Taranaki. Since December we have undertaken analysis[1] on our continued operations at New Plymouth, prompted in part by discussions with the site owner, Port Taranaki. This analysis concludes that it is economic for us to decommission our New Plymouth substation and exit the site completely by 2018 to avoid costs associated with the New Plymouth site and reduce transmission losses. We have revised the POD, and the preferred option is now to install a new 250 MVA transformer at Stratford and convert the New Plymouth-Stratford 220 kV circuits to 110 kV in RCP2. *Exiting New Plymouth substation* The site owner would like us to leave as soon as possible and plans to demolish parts of the site affecting our control room. We are in discussions with the owner. *Meeting the GRS: Long term interconnection configuration in the Taranaki region* The Electricity Industry Participation Code (Code) defines Stratford, New Plymouth and Carrington Street as part of the core grid. The peak demand at grid exit points supplied by the 110 kV network is approaching 150 MW in 2014[2]. This is expected to increase to over 250 MW over the next 40 years. The replacements for Taranaki interconnecting transformers (ICTs) should be a standard 250 MVA three phase unit to meet the 40 year

[1] *Taranaki 110 kV Regional Plan (*Options identification and technical analysis*)* and *Taranaki 110 kV RCP2 Options Analysis (*Economic analysis*)*

[2] This is based on the actual regional peak load for 2014.

	demand forecast. The existing generation at Patea, Whareroa, and McKee has a limited ability to respond to electricity market signals from constraints at times of regional peak demand on the interconnecting transformers. Patea (31 MW) is a small hydro scheme with limited storage. The output of the Whareroa cogeneration plant (70 MW) is linked to the operation of the Fonterra dairy factory and is often reduced during the winter dairy off season. McKee (100 MW) was built to take advantage of surplus gas availability from petrochemical processing and its observed dispatch does not correlate well with market prices.
What is the **timing** of the need and the **confidence level** that issue(s) will eventuate	We have a relatively high level of confidence that this work will be undertaken during RCP2. There are outstanding issues due to ongoing discussions with third parties that could affect the timing. However, our investigation to date suggests the work would be best completed in 2018.
Generic assumptions underpinning the need – including any modelling used	The power system simulation tool DigSilent (version 14.1.3) was used to study the power system. Planning assumptions included the following: • no new generation connection in the Taranaki region apart from that which is already committed. See AM09 - Annual Planning Report 2013, Chapter 5 for the generation assumptions; and • varied generation dispatch for generators connected to the Taranaki 110 kV region (McKee, Whareroa, and Patea generation).

Long-list to short-list options analysis

Options

The Code requires us to consider any transmission investment alongside alternatives such as demand management and supply side options. This table provides a long-list of the options for supplying the Taranaki 110 kV network in the future. We have considered these options against a set of screening criteria in the supporting reports and selected a short-list for further investigation[3].

	Options	Short-listed	Comment
1	Dismantle NPL and NPL-SFD, NPL-CST lines. This option would be supported by demand response and/or constraining on generation on the 110 kV network	×	Generation and demand response may defer transmission investment for the short term. This will be considered further in the full investigation.
2	Stay at NPL	✓	Short-listed – reference case.

[3] *Taranaki 110 kV Regional Plan (*Options identification and technical analysis*)* and *Taranaki 110 kV RCP2 Options Analysis (*Economic analysis*)*

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	3	Change NPL to only 110kV substation, dismantle NPL-SFD, new ICT at SFD	×	This option has lower capacity, poor voltage performance and will create higher losses relative to other options.
	4	Leave NPL, connect NPL-SFD, NPL-CST lines near NPL substation, new ICT at SFD	✓	Short-listed
	4a	4 but connection further from NPL substation	×	Costs may be similar to option 4. Lines around 150m apart at point of connection. This will be investigated further in the full investigation.
	4b	4a but connection further from NPL substation	×	Cost likely to be higher than 4 and 4a due to the lines being about 900m apart at point of connection.
	5	Leave NPL, dismantle NPL-SFD, NPL-CST lines, new ICT at SFD	×	This option has lower capacity, poor voltage performance and will create higher losses relative to other options.
	6	Leave NPL, dismantle NPL-SFD, NPL-CST lines, new CST-SFD line, new ICT at SFD	×	Requires new line of around 35km that will be expensive
	6a	Same as 6 but new line uses part of NPL-SFD line	×	Still around 11 km of new line required making more expensive than option 4.
	7	New NPL site	×	Not short-listed at this stage as likely to be more expensive than option 2. However, we are still investigating this as this option would not require a 33kV cable to Moturoa from CST.
	8	7 but bond NPL-SFD and CST-NPL circuits	×	Very similar to 7 and not short listed for similar reasons.
	9	4 but bond NPL-SFD and CST-NPL circuits	×	Very similar to 4 and 4 technically preferred.

Short list

This short-list presents options 2 and 4 with alternative interconnector capacities and exit timing.

We have two options for standard ICT capacities at New Plymouth or Stratford. 150 MVA would meet current capacity needs, and 250MVA would meet Taranaki 110 kV demand forecast over its economic life. The two options for investment in ICTs are therefore:

a) installing a 250 MVA when the initial work is carried out, and
b) installing a 150 MVA unit at the time of the initial work followed by a 250 MVA unit in 2030.

The two timing options are:

1) exiting New Plymouth in 2018 to avoid the cost of relocating the control room, and
2) exiting in 2021 when we expect the existing New Plymouth ICT will be replaced.

Option 2-a – Replace New Plymouth ICT with a 250 MVA unit in 2021	The New Plymouth substation remains in service. The control room is relocated in 2015. A 250 MVA ICT replaces the existing unit at New Plymouth in 2021.
Option 2-b –Replace New Plymouth ICT with a 150 MVA unit in 2021 + upgraded interconnection around 2030	The New Plymouth substation remains in service. The substation control room is relocated in 2015. A 150 MVA ICT replaces the existing unit at New Plymouth in 2021. We assumed due to load growth that the ICT is replaced with a larger unit in 2030.
Option 4-1a –New 250 MVA ICT at Stratford + voltage conversion in 2018	A new 220/110 kV 250 MVA interconnecting transformer is installed at Stratford in 2018. The New Plymouth-Stratford 220 kV circuits are converted to 110 kV operation and connected to the existing Carrington Street-New Plymouth 110 kV circuits. A new 33 kV supply is installed from Carrington Street to Moturoa (by Powerco).
Option 4-2a – 250 MVA ICT at Stratford + voltage conversion in 2021	A new 220/110 kV 250 MVA interconnecting transformer is installed at Stratford in 2021. The New Plymouth-Stratford 220 kV circuits are converted to 110 kV operation and connected to the existing Carrington Street-New Plymouth 110 kV circuits. A new 33 kV supply is installed from Carrington Street to Moturoa (by Powerco).
Option 4-1b –New 150 MVA ICT at Stratford + voltage conversion in 2018 + upgraded interconnection around 2030	A new 220/110 kV 150 MVA interconnecting transformer is installed at Stratford in 2018. The New Plymouth-Stratford 220 kV circuits are converted to 110 kV operation and connected to the existing Carrington Street-New Plymouth 110 kV circuits. We assumed due to load growth that the ICT is replaced with a larger unit in 2030. A new 33 kV supply is installed from Carrington Street to Moturoa (by Powerco).
Option 4-2b –New 150 MVA ICT at Stratford + voltage conversion in 2021 + upgraded interconnection around 2030	A new 220/110 kV 150 MVA interconnecting transformer is installed at Stratford in 2021. The New Plymouth-Stratford 220 kV circuits are converted to 110 kV operation and connected to the existing Carrington Street-New Plymouth 110 kV circuits. We assumed due to load growth that the ICT is replaced with a larger unit in 2030. A new 33 kV supply is installed from Carrington Street to Moturoa (by Powerco).

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P50 option costs	
Brief description of the approach used to estimate capex, and, if applicable, opex	A desk-top assessment of the high level scope for each option and building block cost was used to estimate the cost for each option and determine the preferred option. Following this, the initial cost estimate for the preferred option was substituted with a 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 option costs are consistent with similar projects completed in the recent past. The table below summarises the costs and benefits of each option.

Net benefits and outputs

The table below compares net costs and benefits of each option relative to the reference case.

Net present value of costs and benefits - $m (2014) [4]

	Option 2-a reference case	Option 2-b staged ICT capacity	Option 4-1a Exit 2018	Option 4-2a Exit 2021	Option 4-1b Exit 2018 staged ICT capacity	Option 4-2b Exit 2021 staged ICT capacity
Transmission capex	$ 20.1m	$ 21.6m	$ 15.1m	$ 15.1m	$ 16.4m	$ 16.6m
Third party sub-transmission reconfiguration	-	-	$ 5.0m	$ 4.0m	$ 5.0m	$ 4.0m
Opex[5]	$ 3.5m	$ 3.5m	$ 3.5m	$ 3.9m	$ 3.5m	$ 3.9m
Rent	$ 2.1m	$ 2.1m	$ 0.2m	$ 0.7m	$ 0.2m	$ 0.7m
Total Costs	$ 25.7m	$ 27.2m	$ 23.8m	$ 23.7m	$ 25.0m	$ 25.2m
Loss Benefits	-	-	$ 3.2m	$ 2.4m	$ 3.2m	$ 2.4m
Terminal value of ICT	$ 0.9m	$ 1.0m	$ 0.8m	$ 0.9m	$ 1.0m	$ 1.0m
Total Benefits	$ 0.9m	$ 1.0m	$ 4.0m	$ 3.3m	$ 4.2m	$ 3.4m
Net Cost	$ 24.8m	$ 26.2m	$ 19.8m	$ 20.5m	$ 20.8m	$ 21.8m
Net Benefit relative to reference case	-	-$ 1.3m	$ 5.1m	$ 4.4m	$ 4.0m	$ 3.1m

Loss Benefits

The load flow-studies discussed in Taranaki 110 kV Regional Plan suggest that option 4 will result in loss benefits in excess of 0.4 MW. We have used the average short-run marginal cost of generation from studies for the BPE-HAY Conductor Replacement Major Capex Proposal to estimate the annual loss benefit in dollar terms.

Terminal Benefits

We have included the terminal value to capture the benefit associated with having a newer transformer at the end of the analysis period. This is particularly the case in the options where a 250 MVA transformer is installed in 2030. We calculated the terminal value by assuming linear depreciation of the transformer over a 60 year life until the end of analysis period. The terminal value is at the end of the analysis period so must be discounted to 2014 in the standard way to obtain the present value.

[4] Taranaki 100 kV RCP2 Options Analysis. Note that the Capex in the options analysis (reproduced here) includes contingency costs.

[5] Includes cost of decommissioning New Plymouth

Option risk assessment	
Risks	There are risks that are common to all options which include cost variations and risks related to construction projects. All options involving our exit from New Plymouth involve timing risks associated with the ability of Powerco to implement a 33 kV supply to Moturoa and ongoing negotiations with Port Taranaki.

Preferred option(s)	
What is the currently preferred option / sequence of options / or short-listed options?	Option 4-1a to install a new 220/110 kV 250 MVA interconnecting transformer at Stratford and convert the New Plymouth-Stratford 220 kV circuits to 110 kV operation and connect them to the existing Carrington Street-New Plymouth 110 kV circuits. The capex for the new Stratford interconnecting transformer and New Plymouth-Stratford circuit conversion is $16.08m. We avoid $2.4m of R&R work in RCP2 by exiting New Plymouth in 2018. We will fund the difference ($13.68m) in the E&D portfolio in RCP2.
Set out the reasons for choosing the preferred **option(s)**.	Option 4-1a minimises the need for further expenditure to meet GRS during the economic life of the transformer.
List key **assumptions** used in determining the preferred option(s).	The assumptions underlying the preferred solution are the supply and demand forecasts, negotiation outcomes with Port Taranaki and Powerco, and the approach to cost estimation, set out above.
List any **interdependencies** which the preferred option is reliant upon for a successful outcome.	The ability to obtain sufficient outages, in both number and duration, to carry out the work are important for a successful outcome.
Steps to completion	
What are the next step(s) in choosing the solution	This project is currently at the BC1 stage which is 'identified need and entry into the integration and approval system' (as per section 3.6.1 of the AM03 - Planning Lifecycle Strategy). At this stage, a preliminary assessment has been carried out to identify long and short lists of options to resolve the need and determine a preferred option. The following step will be the BC2 investigation to finalise the preferred solution. We will start work on this in Q3 2014. 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 Transpower 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	The anticipated timeline is: • BC2 investigation will be conducted in 2014 to confirm the preferred solution; • consultation with affected stakeholders will be concluded in late 2014; • the preferred solution will be submitted for approval around end of 2015; • BC3 for project execution will be completed around Q2 2016; and • expected commissioning date is 2018.
Identify the key services and assets that will need to be procured to complete the preferred option	Depending on the preferred solution identified in the detailed assessment (BC2) phase, key assets that will need to be procured may be all associated equipment to install a new 220/110 kV 250 MVA interconnecting transformer at Stratford and convert the 220 kV Stratford-New Plymouth circuits to 110 kV operation, associated buswork, and 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 to 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.
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 project scope is adequately defined and it can be implemented within the required timeframe and cost. • We will ensure the project is designed to its specification, the appropriate design reviews are completed and 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.	AM03 - Planning Lifecycle Strategy Taranaki 110 kV RCP2 Options Analysis Taranaki 110 kV Regional Plan
Provide a schedule of any models used (including descriptions of model operation and scope).	DigSilent version 14.1.3