OTERANGA BAY TO HAYWARDS A LINE (CHURTON PARK SECTION) RECONDUCTORING

ATTACHMENT D: OUTAGE MODELLING REPORT

Transpower New Zealand Limited
Keeping the energy flowing




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1 Executive Summary

This attachment outlines our modelling of outage options.

Each OTB–HAY A line circuit connects one HVDC pole to the AC system at Haywards. Therefore, an outage of one OTB–HAY A circuit will require one of the two HVDC poles[1] to be out of service (monopole operation). To undertake the proposed project work and the replacement of Valve Based Electronic Equipment for Pole 2 approved in RCP2 we require the HVDC to run on monopole operation for 13.3 weeks. We have combined the outages to minimise the outage time for these two projects.

Alternative outage options

We have received support for this project[2] however submitters raised the issue of the outage length and timing, and have commented on options to mitigate the market impact of the outages in a wet or very wet hydro year.

We have analysed a number of alternative outage options in response to stakeholder feedback. The below table summarises these outage alternatives.

Overall, we consider that conducting the work over one summer, post-Christmas (Base case scenario) to be still the most efficient and economic way of delivering this work.

Outage Option	**Expected benefit** (normal" hydro conditions)	Comment
1. Base Case: Complete the work in one summer over January to April 2020	$0	
2. Complete the work in one summer but start in December 2019	-$1950k	Enabling works need to be completed in spring, so earliest month work can commence is Nov/Dec. Crews need to break for Christmas which introduces inefficiencies in the staging of the work, and remobilisation. Results in longer outage period.
3. Hire more linesman to reduce the outage length	-$1800k	The initial constructability investigation considered adding a third wiring crew, but this only reduced the outage length by 4 days. 2 wiring crews is the most productive and cost efficient option.

[1] HVDC capacity can be maximised by ensuring Pole 2 is always the pole that is out of service; however, this is likely to increase the number of bi-pole outages required.
[2] Ref Section 5, Stakeholder Engagement

4.	Complete the work over two separate summers	-$1350k	Would result in lower system cost impact, however this is outweighed by the significant re-mobilisation costs in the following year. In a wet hydro year it could be justified economically, however, there is no guarantee that hydro conditions the following year will be "normal".
5.	Two-week break in the outage period	-$1150k	Additional construction costs (standing down the crew for 2 weeks) only justified economically in a wet year (1 in 5).
6.	Last minute (unplanned) delay due to market conditions	-$2650k	Would result in lower system cost impact, however this is far outweighed by the significant re-mobilisation costs in the following year, and the last minute crew stand down costs. Would have major impact on delivering other reconductoring projects.
7.	Full pole bypass	-$3850k	Infeasible to construct by 2020 Likely to cost $12+m to reduce outage length by 9 weeks (outage still required during VBE replacement). Uneconomic in 90% of hydro years.
8.	Partial bypass	-$2800k	Infeasible to construct by 2020. Likely to cost $6m to construct the partial bypass, but outage period only reduced by 2 weeks.
9.	Electrode bypass	Less than partial by-pass	Infeasible to construct by 2020 if external to the line easement as will be similar design to a full bypass. Impinges safety clearances and interferes with construction activities if strung on the existing towers. One pole would still have to be taken out of service to allow the safe reconductoring of the electrode line.

Effect of Tiwai Closure

In the unlikely event Tiwai were to close before the re-conductoring commences, the expected market costs from a single pole outage would increase since there would be higher transfers from South Island generation. However, transmission constraints in the lower South Island would need to be alleviated before the full market capacity could be realised. These constraints would take up to 3 years to complete[3] so the current outage plan for the re-conductoring would occur before the constraints are alleviated.

Nevertheless, the closure would warrant a review of the re-conductoring and outage program. The VBE replacement would still need to proceed because of the risk presented to HVDC availability by the failing oil filled snubber capacitors and obsolescence of the VBE system.

In order to minimise the risk of clashing with a Tiwai announcement, we have looked at bringing the project timing forward. However, the planning, procurement and

[3] https://www.transpower.co.nz/clutha-upper-waitaki-lines-project-and-tiwai-future-faqs

enabling work prior to an outage will take approximately 18 months to complete, so November 2019 is the earliest we could commence re-conductoring.

2 Analysis of outages

2.1 The outage alternatives

We have undertaken a lot of analysis to try and establish ways to minimise the outage length required to undertake this project. Stakeholder feedback has led to even more analysis. The below table summarises the options we have considered at the various stages of the consultation process.

Table 1 Present value of the outage options ($k)

	Long-list Dec16	Preferred option consultation Dec17				New scenarios Feb 18		
		1	**2**	**3**	**4**	**5**	**6**	**7**
Outage option>>	**Full bypass**	**Base case: Jan-Apr**	**Dec-Mar, break for Xmas**	**Split years: Jan/Feb 2020 & Jan/Feb 2021**	**Jan-Apr, 3 wiring teams**	**Jan-Apr, 2 wk break**	**Partial bypass**	**Delay last minute: Jan/Feb 2020 & Jan/Feb 2021**
Outage length (weeks)	5.4	13.3	15.3	13.3	12.7	13.3	11.3	13.3
Capex PV $k	35,701	25,219	26,192	27,764	27,444	26,092	30,023	29,075
Expected dispatch cost during outage PV $k	1,874	4,640	4,840	4,121	4,439	4,824	3,769	4,121
Less dispatch cost during VBE outage $k	-1,874	-1,765	-1,541	-1,765	-1,765	-1,828	-1,765	-1,765
Net dispatch cost during outage PV $k	0	2,875	3,299	2,355	2,674	2,996	2,004	2,355
Market reserve cost impact $k	0	880	1,010	721	819	917	613	721
Net system cost + capex PV $k	**35,701**	**31,849**	**33,799**	**33,196**	**33,610**	**33,002**	**34,645**	**34,507**
Net benefit vs Base Case	**-3,852**	**0**	**-1,950**	**-1,347**	**-1,761**	**-1,153**	**-2,795**	**-2,658**

In the following sections we discuss the modelling we have undertaken to assess the impact of the outage on system costs and discuss each of the outage options in more detail.

2.2 SDDP modelling of outage alternatives

We have estimated the system costs of the alternative outages using the SDDP[4] model. The assumptions were based on the EDGS "Mixed renewables" scenario, where Tiwai remains operating. We do not consider it necessary to analyse different market development scenarios given that the time-period of interest is short and is in the near future.

The "no outage" alternative was run and the "system dispatch" costs (mostly fuel costs) were compared to an alternative SDDP run with an outage over the period of concern.

Table 1 shows that the expected increase in system dispatch costs, for our "Base Case", is $4.6 million (present value). However, Figure 1 shows that the incremental system cost (2018 real $) could be as high as $40 million in some hydro years. Figure 2 segments the hydro years from very wet to very dry. It is in very wet (lowest 10% of years) and wet years (next lowest 10%) that the costs are highest. The higher costs result from less efficient use of water in wet years, resulting in more fuel being burned.

Figure 3 shows that MW flows are restricted during very wet or wet years. With two poles operating, the second pole provides "self-cover" for the other pole, allowing the HVDC flows to increase to around 650 MW before affecting N-1 reserve risk. However, with a single pole operating, there is no "self-cover", so once flows exceed 400 MW (CGGT capacity) then the HVDC will set the North Island reserve market risk.

In our modelling we assume the single pole capacity is 700 MW for the entire 13.3 week outage period, however, north flows don't rise above 400 MW. More North Island reserves would be required if the HVDC rose above 400 MW, and a lack of plant available to provide this level of cover constrains the HVDC flows.

The restricted flows result in more North Island fuel being burned, increasing system costs. This cost is partially offset after the outage, as stored water is released, however, the net effect is still a rise in system costs (since the use of water is less efficient).

[4] Stochastic Dual Dynamic Programming – a least-cost dispatch model used to determine the optimal dispatch of hydro, thermal and other renewable generation

Figure 1 Incremental system dispatch costs during a single pole outage of 13.3 weeks (Base Case, 2018 real, $k)

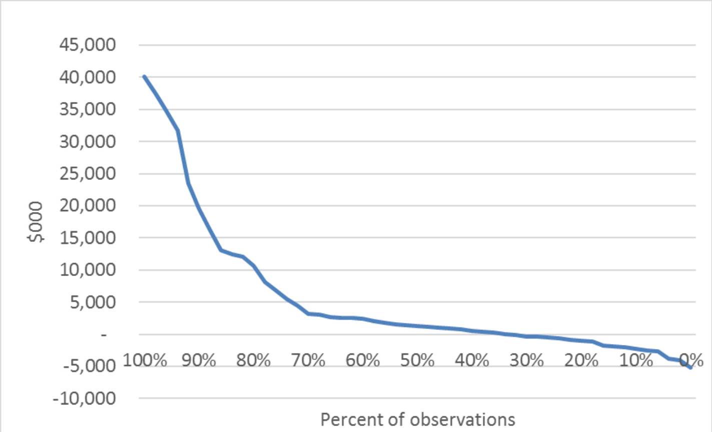


Figure 2 Incremental system dispatch costs from single pole outage of 13.3 weeks (Base Case)

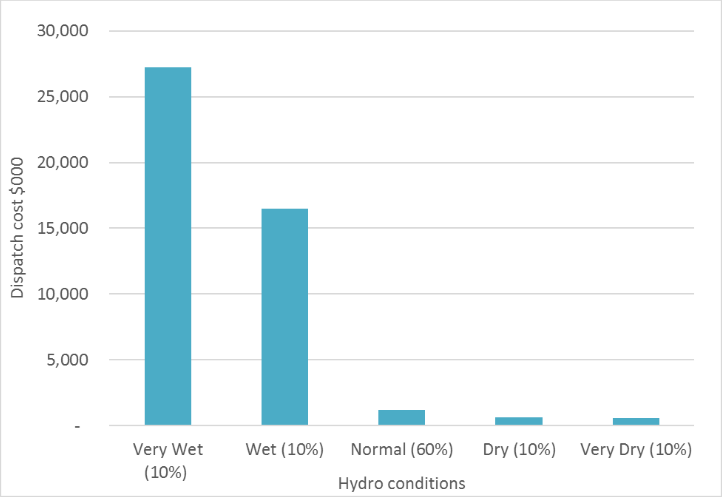
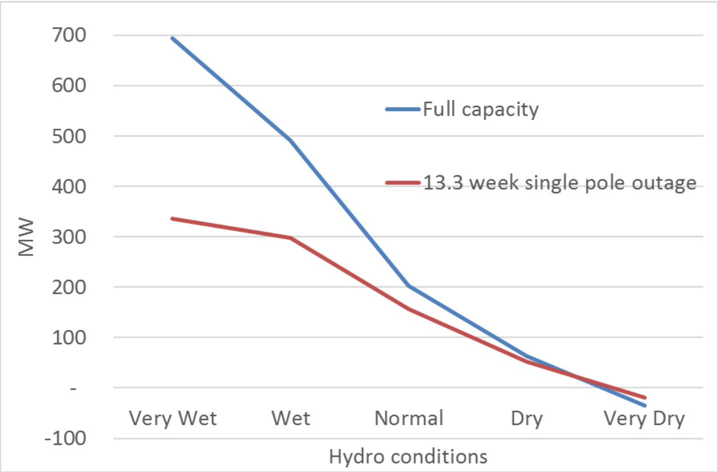


Figure 3 HVDC MW flows during the outage period (Base Case)



2.3 Full bypass considered in the Long list consultation (December 2016)

In our long-list consultation we ruled out a bypass line since we considered its significant cost ($12m) outweighed any generation dispatch benefits it provided from reducing the outage length. In addition, the long lead-in time to build a bypass would mean that the project would not be completed in time to meet the need for this project, and therefore increase the risk of the conductor failing.

The Jacobs report (attachment A in the Long-list consultation) shows in Table 3 the system costs that could be incurred under various scenarios. With no bypass (option 3), under "BAU" conditions, the system cost of the outage would be $1.3 million, but could be as high as $18 million in a "wet" hydro year (1987). The Jacobs BAU scenario used a single hydro year, 1956, which they assumed was a relatively "average" year for hydro flows.

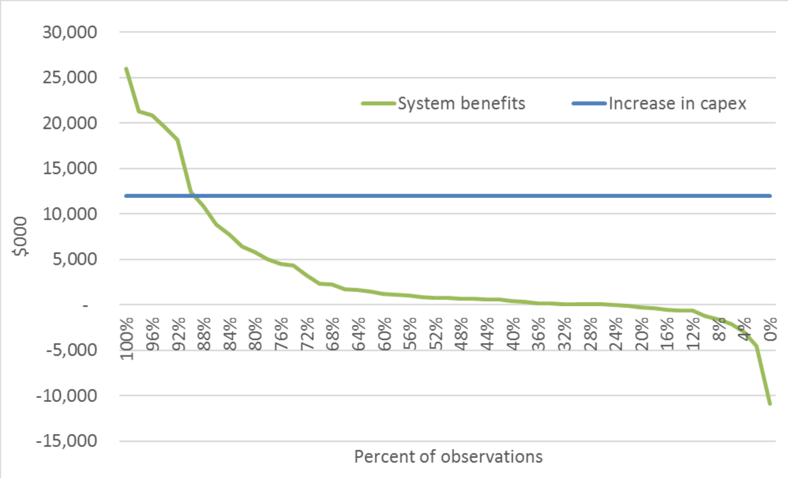
The SDDP modelling presented in this report simulated across 78 hydro years, therefore capturing a wider range of hydro conditions. The system costs in Table 1 above are the average cost taken across all the 78 inflow years. This results in an expected system cost of $4.6 million for our Base Case, which reduces to $2.9 million when we include the mutual benefits of aligning with the VBE outage. These expected values are higher than the Jacobs BAU of $1.5m, since our expected values include the low probability but high cost hydro years (and we also assume the outage is a little longer).

With a full bypass line installed, the expected system cost reduces to $1.9m, which occurs during the VBE outage of 38 days (even with a bypass line there will need to be a monopole outage during the VBE replacement). Since the VBE outage is planned anyway, we can subtract this cost off leaving a net system cost of $0 with a full bypass. This means we save $2.9 million in system costs, when compared to our Base Case outage plan. However, the cost of installing a bypass line would be more than $12 million, so the SDDP modelling in this report still shows there is not a positive expected net market benefit from installing the bypass (Table 1).

Figure 4 shows the range of potential system benefits from all 78 hydro years. The benefit is the remaining 7.9 weeks of outage costs that we avoid by having a bypass (13.3 weeks – 5.4 weeks VBE outage). In about 12% of hydro years there would be a net benefit of installing a bypass. These are typically very wet hydro years when there is higher than normal flows on the HVDC.

Therefore in most years the a full-bypass line would not be economic. Another significant problem with the use of a by-pass line is that, with all the consenting and land use to negotiate, it would not be feasible to implement by 2020. For both these reasons we have ruled out use of a by-pass line.

Figure 4 Incremental system benefits and costs of a full bypass



2.4 Outage options considered in the preferred option consultation (December 2017)

Based on further consultation feedback we considered four outage alternatives in our December 2017 Preferred Option Consultation.

One was our Base Case (alternative 1), and the other three were suggested alternatives put forward by stakeholders during the long list consultation.

The outage alternatives

Alternative 1 is Transpower's current "Base Case":

- A 13.3-week outage from mid-January 2020 to mid-April 2020
- Our costing assumes average weather conditions as per NIWA data with an allowance for loss of productivity due to adverse weather (mainly high wind speeds).
- Any variations in outage timing will also be dependent on us aligning with the VBE outage which is planned during the first half of the work program.

Table 1 shows the net benefit for each outage alternative, when compared to our Base Case (Alternative 1). Alternative 1 results in an expected system cost of $4.6 million in present value (PV) terms. The VBE replacement outage would have occurred regardless of this re-conductoring work. So, we have reduced the outage costs by the expected system costs over the 5.4 weeks of the VBE outage. This results in a net system cost of $2.9 million (PV) for Alternative 1.

However, Figure 1 and Figure 2 show the risk of much higher system costs in wet and very wet years (note that the figures show the dispatch costs for the entire 13.3 week outge period, including the VBE). The potential outage mitigations that were raised by stakeholders include:

Alternative 2: bring the timing forward to December /January (Mercury)

- The planning, procurement and enabling work prior to an outage will take approximately 18 months to complete. It is not possible to commence reconductoring any earlier than November 2019.

- Enabling works (access tracks, tower foundations, etc) will be required before stringing commences. The enabling works will need to occur over spring time when the weather and ground conditions are suitable. Therefore, November is probably the earliest we could begin wiring. Landowner access constraints, a wet winter or higher than normal wind speeds present greater risk that all the work will not be completed within an outage window.

- Wiring crews will break for the Christmas - New Year holiday period for Health and Safety reasons. This means the first stage of the wiring work will need to be stopped and restarted in the new year. The HVDC would be returned to service over this holiday period.

- A longer outage pre-Christmas or splitting the first stage of work into two will introduce inefficiencies that could result in an additional 2 - 3 weeks of HVDC outage (i.e. will require a total of 15 - 16 weeks). Staging of the work would require a longer second outage, require wiring sites to be made secure, temporary works and remobilisation of the work crews.

- The longer outage length for Alternative 2 increases the expected total system cost and also capex (since the crews are required extra days). This results in a net benefit of around $1.95 million less than the Base Case.

- We have eliminated this option based on the **expected** net market benefit.

- Under the CapexIM our investment decisions made now must be based on **expected** value, because we can't predict the future. However, other parties may place greater weight on the low probability / high consequence outcomes, because of the commercial risk this poses to them.

Alternative 3: extend the outage over two summers, so that there is only a 6-week outage in each year (Contact Energy).

- A single 7-week outage would allow the wiring to be completed in January/February 2020, and another 6-week outage over the same period in 2021. The 2020 outage is longer since the VBE testing would need to occur once the re-conductoring is complete.

- Site set up and crew mobilisation costs would be incurred twice, once in 2020, and again in 2021.

- Enabling and temporary protective works would need to be re-established in the second year.

- There are limited resources and opportunities to complete other reconductoring work and this option will displace other work in the second year making those projects more costly.
- Net effect is a net benefit of minus $1.3 million, which excludes potential cost increases in other projects (in year 2).
- Figure 7 (see the Alternative 7 section) shows that under a small range of hydro years the benefits will exceed the costs. However, there is no guarantee that hydro conditions will be any more favourable in year two.
- We have eliminated this option based on the **expected** net market benefit.

Alternative 4: reduce the outage length by hiring more linesman (Meridian).

- We assume in our "Base Case" that 2 wiring crews would be used, plus a third crew would be used for catenary support and/or scaffolding.
- This alternative considers the impact of adding a third wiring crew in order to speed up the work and reduce the outage length.
- The initial constructability investigation considered adding a third wiring crew, but this only reduced the outage length by 4 days. Using two wiring crews is the most productive and cost efficient option given the increased cost of hiring a third crew.
- Net effect is a net benefit of minus $1.8 million, which excludes the additional project risk from needing to co-ordinate an extra wiring crew.
- We have eliminated this option based on the **expected** net market benefit.

Our option analysis in December 17 found that the best option was our preferred (Base case), to complete the work in one summer over January to April 2020 and this was communicated in our December 2017 consultation.

2.5 Additional outage alternatives from December 17 consultation we considered

During our December 2017 preferred option consultation, stakeholders suggested we consider a "partial" bypass alternative, which they thought would reduce (but not eliminate) the outage period. There were also requests for Transpower to stop the reconductoring work part-way if market conditions/hydrology was not favourable

We have therefore considered another three alternatives in our analysis:

- partial bypass,
- two-week break in the outage period, and
- last minute (unplanned) delay due to hydrological conditions.

Alternative 5: pause the work for two weeks in the middle of the outage period.

- After the first 8-week phase of the project is completed, the HVDC could be returned to full bi-pole operation for a period of two weeks before the second phase of work begins. This would result in the project completion being pushed back to 24rd April (currently 10th).

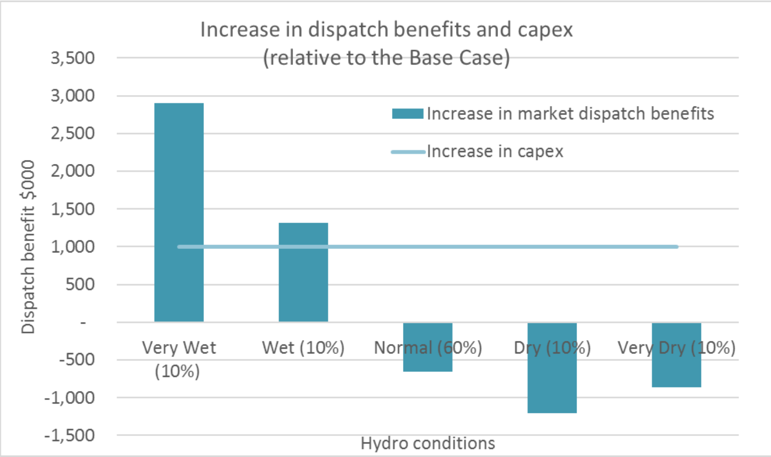
- Two wiring crews would need to be stood down for 8 days which will increase costs. There would also be an additional mobilisation cost with the crews needing to come back after Easter to complete the work (in our Base Case the work is completed prior to Easter).

- The two-week gap would allow additional South Island hydro storage to be released if the lakes were near full capacity. Our modelling indicated there was very little difference in the expected system cost (less than $100k in Table 1) and that the net expected market benefit is minus $1.15 million.

- However in very wet and wet years the dispatch benefits (estimated over the entire 13.3 week outage period, including VBE outage) would exceed the incremental cost (Figure 5). These account for 20% of the hydro years modelled.

- We have eliminated this option based on the **expected** net market benefits, since most of the hydro years show a net market cost.

Figure 5 Dispatch benefits over 13.3 weeks versus increased costs for Alternative 5



<u>Alternative 6</u>: partial bypass.

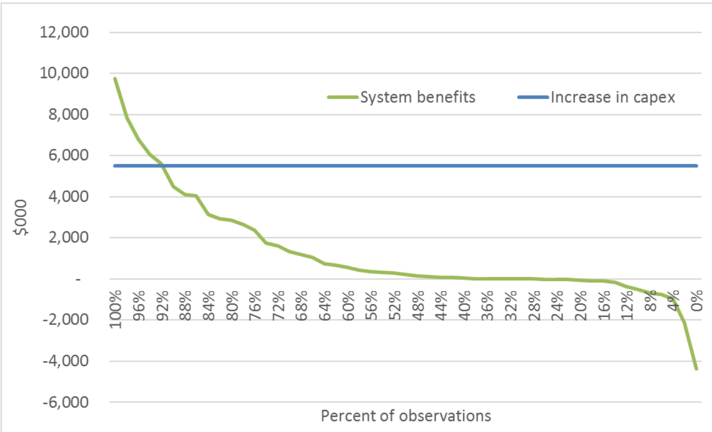
- It is important to note that a bypass would only have value during the Pole 3 reconductoring outage. The Pole 2 VBE replacement work means Pole 2 is not available for service during the Pole 2 reconductoring and therefore a bypass during that period would not eliminate an outage.

- The line route to be reconductored has two sharp 90-degree bends approximately 4 km apart which naturally divides the work into 3 wiring sections

A partial bypass could be installed over any of the 3 wiring sections ahead of the construction period.

- We have determined that two fully resourced crews are the most efficient and economical way to carry out the work in the shortest time possible. Having two crews working on different sections at the same time negates the time saving a single section bypass could provide. We estimate 4 km of bypass line would cost a at least $6m to install and remove (assuming property rights could be obtained within the required timeframe). Practically we do not believe that there is sufficient time to acquire property rights, design and build a partial bypass line ahead of wiring in 2020.
- Extending the work into 2021 would not match with the VBE replacement or fall within RCP2.
- A partial bypass would at best reduce the outage period by 11 days, with a return to service expected around the 27th March (Base Case is 10th April). Another day outage is needed to change over from the bypass.
- The expected net market benefit is minus $2.8 million (although the below figure shows there are around 8% of inflow years where the benefits would exceed costs).
- We have eliminated this option based on the **expected** net market benefit, and the likely infeasibility of completing the partial bypass within the required timeframes.

Figure 6 Incremental system benefits versus costs of Alternative 6



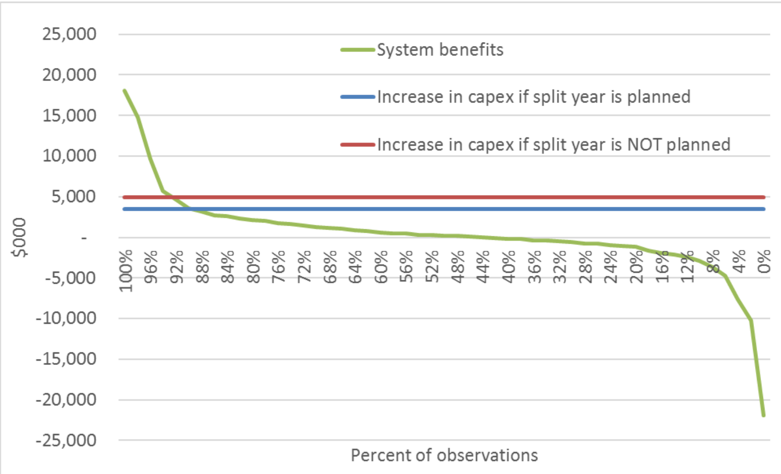
Alternative 7: delay last minute

- This is similar to alternative 3, where the outage is split over two years, however the delay of the second tranche of work would occur at the "last minute" in response to very wet hydro conditions.
- The VBE work would still need to proceed, because replacement cannot be deferred due to the importance of this work. Therefore, we would still complete

phase one of the project as planned, and then delay the second phase by a year.

- This would incur significant costs for standing down wiring crews, and there would also be additional mobilisation costs incurred in year two.
- If we assume "expected" system costs, this results in a net overall cost of \$2.7mill compared to the Base Case (Table 1) .
- In Figure 7 there are only around 6% of hydro years where there is a net market benefit (estimated over all of the outage period, including the VBE). However, this would also be contingent on the subsequent year returned to normal (or not wet) hydrology.
- The expected net market benefit is minus \$2.7 million.
- We have eliminated this option based on the **expected** net market benefit.

Figure 7 Incremental system benefits (over 13.3 weeks of outages) versus costs of Alternatives 3 and 7



2.6 Summary of the alternative outage options

The reconductoring of the Churton Park section of OTB–HAY A is supported by stakeholders. However, the outage period length (13.3 weeks) required to undertake the work is causing some concern amongst stakeholders – particularly the generators Meridian and Contact.

- We initially considered a bypass, but found that the costs of this to be prohibitive to the benefits under the Investment Test. We also consider it infeasible to implement to meet the need date for the replacement of the conductor.
- A number of other outage alternatives were also considered, all of which were considered by their costs and benefits as allowed by the Investment Test – including a partial bypass as well as stopping the work midway

should market conditions be unfavourable. Our base case option still was found to be the best option.

- Overall we still consider our base case option is the best option. In some more extreme hydrological sequences we recognise the outage length could have an impact on generation dispatch costs. We cannot predict the type of hydrology that will exist in 2020. Therefore, we have based our decision on the likely conditions based on historical hydrological inflows.
- Our intent is to continue to undertake a 13.3 week outage. We consider this provides generators with some certainty over our plans and the ability to hedge positions and manage lake levels based on this information. However, we will review this position closer to the time of the outage and in view of hydrological conditions. If, for some reason, the System Operator declared a grid emergency or if system security was challenged, we would consider deferring the outage, following our normal procedures, and based on actual conditions at that time.