TPM second issues paper questions and Authority responses

This document sets out questions and answers of general interest to submitters.

The Authority's answers are in red. Information that relates only to a specific entity's business, and/or may be commercially sensitive or confidential, has been removed and is denoted by **"[Information removed]"**

Note: There have been further, more recent, questions from parties. These questions and any others, and the Authority's responses, will be added once they are finalised.

List of questions and Authority responses – dated 15/07/2016

1. Transpower
2. Westpower
3. Major Energy Users' Group (MEUG)
4. Electricity Ashburton
5. Mighty River Power (MRP) (2)
6. New Zealand Aluminium Smelters (NZAS)
7. Oji Fibre (previously Carter Holt Harvey)
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15. EnerNOC New Zealand Limited
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Additional attachments

1. TPM_questions_and_responses_transformer_capacity_added_18July2016
2. TPM_questions_and_responses_CBA_assumptions_and_diesel_costs_added_22July2016

The following parties asked questions that relate only to their own circumstances / are not of general interest to submitters:

1. KiwiRail
2. Pioneer
3. Golden Bay Cement (GBC)

1. Transpower query responses

Authority responses are in red.

<u>Transpower</u>

We've been having a look at the CBA work by OGW and had a few questions that we are hoping you could answer, or get them to answer. These are set out below with screen-grabs of where in the CBA model the question relates to.

Would you be able to tell me when you could provide this? Hopefully all a straightforward to answer but let me know if any questions.

All questions relate to the file CBA_input_file_TPM_scenarios.xlsx

<u>Item 1: Basis of split of capex between 'generation' and 'load'</u>

Sheet: *Input*
Cell Reference: *B11:C12 (see figure below)*

Can you please provide a more specific reference for the source of these capex assumptions? In particular, can you please clarify:

- the basis for the split of future capex between generation and load?; and
- whether these values (ie, 60 and 40 per cent) signify an allocation of the additional cost of transmission capacity, and/or whether they are directly related to the Area of Benefit Charge?

In answer to your questions:

- The 60:40 split between load and generation is an approximation. It reflects a high level understanding that economic investments benefit generation and load while reliability investments are of a greater benefit to load. Given its broad approximation the Authority assessed the sensitivity of the CBA to changes in the load/generation split. It was found that a higher portion to generation would increase the "more efficient generation" benefit but also reduce the RCPD benefit, and vice-versa–so in terms of the total quantum of benefits of the Authority's proposal, an offset exists. Note that the sensitivities that were undertaken were not reported in the Oakley Greenwood (OGW) CBA because, given the sheer number of sensitivities that have been undertaken in relation to the CBA, OGW considered that it was not useful to provide all of them.
- The split is not related to the area-of-benefit charge. It is a high level approximation that reflects the uncertainty that existed around Transpower's 20-year capital expenditure programme at the time the CBA was prepared.

<u>Item 2: Calculation of generator operating capacity</u>

Sheet: *Volumes by Gen*
Cell Reference: *Volumes by Gen K35:L45 (see figure below)*

Based on our review of the calculations in these cells, it appears that OGW has calculated the operating capacity of each plant in each region using a weighted average capacity factor. Put another way, the operating capacity of each plant is determined by its capacity multiplied by the weighted average capacity factor of plants in its region. Is this intentional and, if so, what is the rationale for such an approach? Are these assumptions used as the basis for OGW's assessment of plant operating costs?

In answer to your questions:

- The 'weighted average conversion factor by region' is simply used to estimate the starting 'operating capacity in MWh' for each of the four regions OGW modelled. The starting operating capacity in MWh figure (for each region) gets inflated by the growth rate in demand (~1%-1.5% per annum) to estimate the incremental growth in output (the numerator) in the $/MWh LRMC (for transmission) calculation.
- Neither the 'weighted average conversion factor' nor the 'operating capacity in MWh' affects the costs of operating any of the new generation plants in the assessment.

<u>Item 3: Basis for and function of 'allocation' values</u>

Multiple Sheets:
S1a (Huntly stays);
S1b (Huntly goes); and
S2 Low investment scenario.

Cell reference: *C6:C9 (see figure below)*

These 'allocation' values are exogenous to the model, and so we are keen to understand whether these values have been:

- calculated elsewhere, in which case can you please provide the model/program that has been used to calculate them?; or
- assumed, in which case can you please explain the basis for the assumption?

Moreover, what is the logic underpinning these values in the model, i.e., what are they intended to represent?

In answer to your questions:

- A number of sensitivities were applied on allocating major capex between regions for load and generation. This was not reported in the OGW CBA. Sensitivities where also applied in relation to the change in cost of a given quantity of capex. Given the uncertainty around major capex over the 20 to 30-year analysis timeframe, assumptions were necessary. For the final load split, a table was compiled using historical and forecast major capex information, as per below. The assessed benefits of investments and location of investments required some judgement. Transpower's updated "RT06" file was used to source information. This spreadsheet is published by Transpower and is available on the web. Note the average major capex in the RT06 file between 2004 and 2025 was $154m pa whereas the major capex scenarios were based on $50m and $100m pa respectively.

Year	UNI	LNI	USI	LSI	Total	Source
2004	2062536.938	1,719,583	1,688,558	81,113	5,551,791	Actual based on where investment is located
2005	154769.839	78,852,633	7,310,984	65,501,658	151,820,044	Actual based on where investment is located
2006	6137163.249	5,788,269	5,782,413	1,975,821	19,683,666	Actual based on where investment is located
2007	105763.014	4,536,760	737,799	364,244	5,744,566	Actual based on where investment is located
2008	3477821.515	2,030,953	6,454,077	669,293	12,632,144	Actual based on where investment is located
2009	5825516.683	479,483	213,653	2,970,147	9,488,799	Actual based on where investment is located
2010	188,200,191	80,022,532	44,731,776	23,862,771	336,817,270	Actual based on assessed benefits
2011	319,388,502	110,140,416	35,233,930	31,778,072	496,540,920	Actual based on assessed benefits
2012	383,958,039	136,269,870	59,023,865	44,455,558	623,707,333	Actual based on assessed benefits
2013	242,827,953	85,970,234	29,131,337	33,680,394	391,609,919	Actual based on assessed benefits
2014	121,071,738	55,351,271	25,445,769	31,400,063	233,268,841	Actual based on assessed benefits
2015	37,174,756	23,775,571	11,644,091	19,735,142	92,329,560	Actual based on assessed benefits
2016	33,526,077	24,905,962	10,627,750	20,627,750	89,687,539	Forecast based on assessed benefits
2017	38,059,947	28,491,974	9,109,550	23,589,550	99,251,021	Forecast based on assessed benefits
2018	44,362,395	46,848,238	5,561,250	15,503,250	112,275,132	Forecast based on assessed benefits
2019	34,649,116	51,775,282	975,000	975,000	88,374,398	Forecast based on assessed benefits
2020	14,738,164	38,336,235	433,000	433,000	53,940,399	Forecast based on assessed benefits
2021	24,450,350	27,619,255	24,673,582	8,525,456	85,268,642	Forecast based on assessed benefits
2022	35,487,910	27,584,209	25,557,647	6,370,234	95,000,000	Forecast based on assessed benefits
2023	47,027,855	41,044,264	25,557,647	6,370,234	120,000,000	Forecast based on assessed benefits
2024	50,297,293	35,338,403	10,376,861	13,987,443	110,000,000	Forecast based on assessed benefits
2025	71,288,240	55,132,299	16,691,798	18,916,663	162,029,000	Forecast based on assessed benefits
Average capex	77,466,913	43,727,895	16,225,561	16,898,766	154,319,136	
	50%	28%	11%	11%	100%	
Allocation for $100m annual major capex	50,199,162	28,336,016	10,514,290	10,950,532	100,000,000	
Allocation for $50m annual major capex	25,099,581	14,168,008	5,257,145	5,475,266	50,000,000	

Item 4: Basis for and function of 'allocation' values

Multiple Sheets:
S1a (Huntly stays);
S1b (Huntly goes); and
S2 Low investment scenario.

Cell reference: *C45:C48 (see figure below)*

In a similar vein to item 3 above, can you please provide information as to the basis of these 'allocation' values, and the logic underpinning their inclusion?

- The allocation to regions for generation was based on GWh produced in each region. 2014 generation data was used. A simplified allocation method was applied here because of the difficulty of allocating the benefits of investments to specific generators (without running a tool such as vSPD to determine the beneficiaries for each assumed investment).

Item 5: Capacity value of wind farms

Multiple Sheets:
- *Project list_gen-S1a)Huntlystay;*
- *Project list_gen-S1b)Huntlygoes;*
- *Project list_gen-S2b)_Low_Inv*

Cell reference: Column Q

Based on our understanding of OGW's approach, it appears as though plants are constructed according to the order of the 'project lists' set out in these sheets. Plants are constructed to meet growth in maximum demand. It appears from the worksheet that much of the new build in most scenarios comes from wind farms. From our review of the model, it appears that the model assumes implicitly that wind farms provide 100 per cent firm capacity. Is this correct, or has OGW derated the capacity of the wind farms to reflect the intermittent nature of their generation? If OGW has derated the capacity of the wind farms, where is this adjustment done in its modelling?

As noted by Transpower, OGW adopted a simplifying assumption regarding wind (i.e., it was not de-rated).

The assumption about the wind farm's capacity affects both states within the modelled time frame of 20 years (i.e., if wind farms are de-rated, then the model would build exactly the same amount of additional capacity under both the proposal and the status quo cases), hence OGW's view is that the impact on the CBA results is not likely to be material.

Item 6: Modelling of new generation investment decisions

Multiple Sheets:

- *Project schedule_S1a)Huntlystay*
- *Project schedule_S1b)Huntlygoes*
- *Project schedule_S2a)_Low_Inv*
- *Project schedule_S2b)_Low_Inv*

How has OGW calculated the Project Schedules set out in these sheets. In particular, are the results on this sheet:

- derived through the running of least cost dispatch and planning model; or
- are the manual, hard-coded calculations set out in this worksheet the basis of the calculations.

We are particularly interested in whether OGW's approach accounts for the annual profile of demand. Based on our review of the model, it appears as though all planning decisions made so as to meet *maximum demand* requirements, and so varying energy output of individual plants is not explicitly included in the model. Is this an accurate description of OGW's approach?

This is correct, the model accounts for maximum demand requirements only. The reason for this is because there is a lack of information to incorporate annual demand profiles for individual plants.

If OGW were to change the assumptions to build new capacity based on the annual profile of demand it would affect both states, hence OGW's qualitative view is that doing this would not likely materially impact the CBA results.

Item 7: Treatment of 'spare capacity' in the Huntly Stays scenario

Sheet: *Project schedule_S1a)Huntlystay*

Cell References: *E8 and G62 (see figure below)*

In OGW's model, rows 14 and 62 show the quantum of new generation investment required to meet increases in demand. In the Huntly Stays scenario, the 'New Schedule' assumes that Huntly's spare capacity is available, and so there is no shortfall in capacity. The value of Huntly's spare capacity (435 MW) is represented in cell C8, and is included in the value in row 14. However, the corresponding cell for the 'Old Schedule' in row 62 references cell E8, which is empty. From our perspective this appears to be a cell referencing error. Is that correct and, if so, has the error affected OGW's results? If it has affected the results, how would amending the error affect OGW's estimate of net benefits for this scenario?

It was a reference error; it makes no difference to the actual result.

2. Westpower

Authority response

While at first glance there appears to be a difference in modelled and 'status quo' charges for Westpower, please note:

- The Authority has not included the connection charges in the charts/tables. It is assumed to be largely the same for the status quo and proposal, therefore connection charges were not included in the comparison.
- The Authority has not modelled an HVDC charge on Westpower as the generation plants in their network is less than 10MW (the Authority does not have the half-hourly data to model them). The Authority recognises that the HVDC charge relates to connected generators (clause 32 of the TPM).
- The status quo modelled is for the 2019 year, with amendments to current TPM based on Transpower's operational review. The charges Westpower has provided are current (April 2016). This results in differences as follows:
    - The TPM will use n=100 (not n=12) for the upper South Island RCPD calculation, and
    - The TPM total revenue requirements are different.
- There may also be a difference caused by the way 'Loss and Constraint Excess' (LCE) is handled. In the modelling it is netted off the revenue requirement prior to the allocation of interconnection charges. This may not be the case in the actual Westpower charges.

The table below provides a like-for-like comparison. The status quo interconnection charge the Authority calculated for 2019 of **$1.60m** is similar to Westpower's current interconnection charge of **$1.69m**.

[Information removed]

Questions

As discussed briefly we have concerns regarding the transmission charge information in the Second Issues Paper.

Specifically, the Status Quo charges on page 223 are shown as $1.6m, whereas as you will see from the attached, the figure is $2.6m. The Proposal figure of $4.7m, when compared to our current charges plus ACOT payments is in fact approx.$0.6m less in total.

When this is compared to a factor of three increase in the modelled charges per MWh on page 226, it would appear that something may not be correct. The documents therefore provide us with no ability to model with any confidence the impact of the change (on the indicative basis provided).

As we are to meet with your Chair and Chief Exec on Friday, we need to have clarification of the proposal today.

3. **Major Energy Users' Group (MEUG)**

Authority Response

1. The TPM cost benefit analysis spreadsheets are now available on the Authority's website.
2. The file that provides this information is the regulated asset base (RAB) excel spreadsheet which Transpower maintains. We have contacted Transpower about making this information publicly available we are waiting to hear back from them.
3. The total annual revenue requirement for the 2015/16 pricing year for area-of-benefit investments was provided by Transpower at the Authority's request (see below). Transpower informed the Authority that the annual revenue requirement amounts (in $m) include revenue for the capital and operating and maintenance (O&M) components. Transpower did not provide a further breakdown. Note that Transpower would need to develop an operating and maintenance allocation for area-of-benefit assets in its development of the TPM.

Large investments		
Investment	Rev Req ($m)	Modelling approach
NIGU	85.3	Allocation as per vSPD
Pole 3	72.9	
Pole 2	45.1	
NAaN	39.2	
LSI Renewables	4.2	
Wairakei Ring	14.8	
Otahuhu GIS	12.0	Allocation based on regional beneficiary approach
BPE-HAY reconductoring	5.5	
USI reactive support (IGE 4)	3.5	
UNI dynamic reactive support	5.5	
LSI Reliability	2.1	
Totals	**290**	

Transpower's total revenue requirement of $971m for 2019/2020 can be broken down as follows:

Area-of-benefit charge high value investments:	$290m
Area-of-benefit charge low value investments:	6m
Residual charge (exclusive of overheads):	$302m
Overheads	$198m
Connection charge	$125m
Loss and Constraint excess income	$ 50m

4. Distributed generation information was provided by distributors. Some distributors have advised that the information is commercially sensitive and accordingly the Authority is not publishing it at this time. Note that the Authority does publish some information on generators, including distributed generation. This is available on EMI at www.ea.govt.nz. Access information through datasets/wholesale/generation.
5. Please access the attached hyperlink below for an AER document that discusses the use of prudent discounts in Australia. https://www.ausgrid.com.au/~/media/Files/Network/Electricity%20Supply/Network%20Pricing/Pricing%20methodology%20for%20transmission.pdf.
6. The workshops are:
   - Auckland 14 June
   - Wellington 15 June
   - Invercargill 16 June
   - Christchurch 17 June

   Exact times of the day are yet to be finalised. The Authority will advise parties when the times have been finalised.

MEUG Questions

We have a copy of the spreadsheet "Results_20160517b.xlsx" and note it is available at http://www.emi.ea.govt.nz/Datasets/Browse?directory=%2FResults_spreadsheet&parentDirectory=%2FDatasets%2FSupplementary_information%2F2016%2F20160517_TPM_second_issues_paper. Some of the information below refers to that as "The EA spreadsheet". The list that follows is in no particular order other than receipt of a request from members:

1. The information in the EA spreadsheet does not seem to cover either the assumptions or the modelling used in the Oakley Greenwood CBA. It would be very helpful to have this. Some of the information could be inferred from the description of the CBA in the TPM second issues paper, but access to the modelling would provide a more reliable foundation for analysis.

2. Can we have access to Transpower's asset register, showing for each asset:
   - Charge category – AOB or Residual.
   - Book value (DHV) used for determining revenue requirement
   - Physical location (at least NI/SI or region)

3. Can we have a breakdown of Transpower's regulated revenue requirement in the following categories:
   - Revenue attributable to recovery of asset value for AOB assets
   - Revenue attributable to recovery of O&M allocated to AOB assets
   - Revenue attributable to recovery of asset value for Residual assets
   - Revenue attributable to recovery of O&M allocated to Residual assets
   - Revenue attributable to recovery of O&M not allocated to assets
   - Revenue attributable to recovery of overheads

- Revenue attributable to connection assets
- Other regulated revenue

4. A list of distributed generators and a list of co-generators and sufficient information so we know where they are located and how they are defined as either DG or co-gen.

5. As mentioned at the meeting yesterday please provide references for other jurisdictions that use PDP.

As our analysis proceeds we may request further information.

Finally just a quick note that as early as possible notice of the dates for the workshops, timing and agenda would be helpful.

The above request for information is not confidential.

4. Electricity Ashburton

Authority response

Sorry for the delay in getting back to you. Electricity Ashburton's residual charges are based on the following gross AMD data. I have sourced this information from the "results" spreadsheet that supports the TPM second issues paper - available on the Authority's website. You will note that the two offtakes are not aggregated and so the AMD of each node is calculated separately.

Network	poc	Gross MW	Net MW
Electricity Ashburton	ASB0331	39.1734	39.17399979
Electricity Ashburton	ASB0661	158.0271	156.4960022
		197.2005	

We note your email below which suggests that aggregating the two nodes would address the issue you have raised. The Authority encourages Electricity Ashburton to address the point in its submission on the second issues paper.

[Information removed]

Note paragraph 7.183 of the second issues paper–gross AMD includes electricity generated by generation connected to the customer's network, demand-side management and demand response.

Note also that Transpower may opt to base the residual calculation on line or transformer capacity rather than gross AMD.

Questions

A constructive catch up on Tuesday – Thank you. A follow up thought – sorry I only had your email on file.

After we spoke it still bothered me that there must be something else , other than seasonal diversity, for Ashburton's resulting $/MWh to be so much higher than our regional neighbours. A deeper dive into the data/calculations used has highlighted a potential explanation.

Ashburton GXP has two nodes – one at 66kV and one at 33kV. The 66kV node effectively supplies the rural (irrigation) network plus has Trustpower's Highbank generator embedded. The 33kV node supplies the urban area of Ashburton. The two nodes interconnect at the 220kV bus but also we have a physical interconnection transformer to allow backup switching between the nodes.

During Winter the load profile is such that during low usage times the 66kV node exports Highbank output and this is taken up by the 33kV node – i.e. no effect on the grid. For this reason Transpower aggregate the metering values/charges across the two nodes. A simple summation double counts the exported quantity from the 66KV

node. At a high level I would expect the allocated ATMD capacity to reduce by about 3-5 $/MWh if the nodes were aggregated – putting Ashburton more in line with the regional neighbours.
Before I get the consultants diving into this I was wondering if your analysts could have a quick look firstly to understand the situation and secondly to get a feel of the resulting numbers if the nodes were aggregated.

5. Mighty River Power (MRP) (2)

Authority response

Sorry for the delay in a response. The proposed guidelines provide for the prudent discount to apply to all transmission charges, not just the residual. As noted in paragraph 7.231 of the second issues paper, the main policy rationale for granting a prudent discount is to avoid inefficiencies arising from the residual charge.

Question

You'll be on the TPM roadshow no doubt but I wanted to see if I heard something correctly the other day – did you say the PDP would only apply to the residual charge or will it apply to all the charges (noting it would be pegged to commodity prices etc)

Authority response in red

Sorry, it has taken some time to respond to your questions. Your questions and our responses follow (in red) below.

1. How and where counterfactual asset scenarios have been modelled for the length of their lives in vSPD code? The vSPD analysis is for one year only, not the asset life. The modelling assumes that the net benefits calculated in relation to an investment correspond with the net benefits that would be obtained over the investment's life.
2. Post processing data has all the nodal and constraints solves but post processing queries utilizing some columns such as "difference in benefit" Is this the difference of the benefit column of base case and the counterfactual case? (We can see the comments that information given is not enough to reproduce the results but we are trying to make sense of those calculations) . Yes, the 'difference in net benefit column' is the difference in the 'net_benefit' column from the counterfactual and base case results. The same applies for 'net_benefit_ir'.
3. Results spreadsheet shows that certain percentages of benefits are assigned to different regions/groups. Was the "difference of benefit" used to come up with these percentages? No. If so, how?-The allocation used for the smaller 4 investments only (i.e. OTA_GIS, USI reactive support, UNI reactive, and LSI reliability) is via fixed allocation to each region by customer type. The allocation between regions/ customer types is based on 'engineering inspection' (and in discussion with Transpower) of the benefits arising from these investments – it's not based on vSPD analysis. The approach is similar to that used in the Area of Benefit charge in the 16th June 2015 TPM Option Paper. Note that 'gross AMD' is used as an allocator between parties, within a region.
4. How were the regions/groups benefiting from different assets determined? Were they determined in advance or as a result of examining the vSPD model

results? The 6 largest investments are allocated via net-benefits calculated from vSPD. The 4 smallest investments are allocated by the 'regional' AoB method discussed in question 3 above.

5. How the "Benefit" and "IR Benefit" is calculated? This is best determined from looking at the code. Refer to lines 2854-2938 for vspdSolve.gms. To summarise: the cost and revenue are calculated for each party at each node and the difference between the two is the benefit. The costs for generators are based on their offers (assumed to be SRMC). The benefit for demand is VoLL – price.
6. It appears that all residual charges related to JVs have been added up in MRP's residual charges. For example, All of residual charges of NAP2201 and NAP2202 have landed at NAP2202 and that has been added to MRP's residual charges. Is this correct? Yes, the NAP2202 residual charges are allocated to MRP (the NAP2201 residual charge is zero).

Questions

With reference to **[Information removed]** email regarding TPM queries; we are trying to understand the allocation of charges and the results spreadsheet. Questions are not particularly all SPD related but a mix of SPD, results and allocation related. Can you help or direct following questions for some sort of answers or explanations?

1. How and where counterfactual asset scenarios have been modelled for the length of their lives in vSPD code?
2. Post processing data has all the nodal and constraints solves but post processing queries utilizing some columns such as "difference in benefit" Is this the difference of the benefit column of base case and the counterfactual case? (We can see the comments that information given is not enough to reproduce the results but we are trying to make sense of those calculations)
3. Results spreadsheet shows that certain percentages of benefits are assigned to different regions/groups. Was the "difference of benefit" used to come up with these percentages? If so, how?
4. How were the regions/groups benefiting from different assets determined? Were they determined in advance or as a result of examining the vSPD model results?
5. How the "Benefit" and "IR Benefit" is calculated?
6. It appears that all residual charges related to JVs have been added up in MRP's residual charges. For example, All of residual charges of NAP2201 and NAP2202 have landed at NAP2202 and that has been added to MRP's residual charges. Is this correct?

Thanks for your help in advance

6. New Zealand Aluminium Smelters (NZAS)

Authority response 1

Please see attached dataset **[Excel sheet 1]** and explanation below. We will come back to you re: the alternative Transpower information.

Explanation

We have opted to provide the Authority's transformer capacity information separately. The information is sourced from the Authority's market model. Note that this is somewhat a work in progress. The information is not tried and tested because we did not use this information to develop charges for the proposal.

The file attempts to determine capacity at each substation/node. AMD is also given using 2014 data.

- Capacity information is from network data from a vSPD case file (23rd June, 2015, TP37) – a high demand period.
- Branch data was filtered to get transformers and their capacity in MW.
- Branch bus numbers were mapped to GXP/nodes to determine voltage level. Where we could we determined the minimum voltage node then used this node to find the following from the Data Warehouse:
  - the network participants at that node
  - Recon_type, (GN – network comp, GD – direct connect, GG – grid connected generation)
  - Island, transmission region types, and,
  - AMD during 2014.
- Direct connected generators and Interconnecting transformers were filtered out.

The 4 Branch columns indicate the transformers used to supply each node. We have assumed that these are all in parallel. We weeded out most of the 'unusual' configurations and used a scale factor on the AMD on these. The 4 Capacity columns give the capacity of the transformers.

The Ncap column is an attempt to sum the transformer capacities that would be needed for the 2014 AMD N security. To do this we have summed the transformers up in a capacity ordered list (high to low). Note this could be done in other ways. We picked the largest transformer first, then the next largest, etc. The Cumsumcap columns are just the cumulative sum of the transformer capacities.

The scale_factor column is the multiplier required from 2014 AMD to the Ncap. The average over all known transformer capacities is x1.6. So where we do not have a capacity I have used this average scale factor of 1.6 to determine a proxy Ncap (ie, 1.6*2014AMD=Ncap).

Note, 1.6x AMD was used for Tiwai's transformer capacity.

Authority response 2

Please see the attached 'alternative' transformer capacity dataset **[Excel sheet 2]** prepared by Transpower.

Note that the information is from early 2014. Further, it is important to note that this was very much a first cut. The information is not 'trialed and tested'.

Regarding your question around transformer capacity for the major generators, the Authority has not further developed either of the datasets. The information provided comprises all of the available data. Note that if the Authority confirms its TPM guidelines, Transpower will be required to consider transformer capacity in its development of a TPM. Transpower's proposal will be consulted on so there will be an opportunity to submit on Transpower's proposed residual charge. The Authority has the role of approving Transpower's proposed TPM.

Questions

we have a request for the provision of information relating to transformer capacity data which would enable us to model one of the methods for allocating the residual charge under the proposed TPM.

The Second Issues paper recommends three methods by which the residual charge might be allocated:

- transformer capacity
- lines capacity
- a form of 5 year gross AMD.

To be able to assess the potential impact of the residual charge to NZAS, and to properly understand any problems with the allocation methods, we wish to model the methods proposed by the Authority. For the three methods, data for AMD and lines capacity is readily available from publicly available sources - AMD data is available from the Authority's EMI data portal and the lines capacity is available from the System Operator's maps and diagrams.

However very little transformer capacity data is readily available. The System Operator's maps and diagrams provides some transformer capacity but very little connection capacity. Transformer capacity is provided with the Electricity Authorities technical data in EMI but again this is not all connection capacity, is error prone to transpose and does not always agree with the System Operators public information.

Therefore, we formally request the Electricity Authority makes the following information available so that participants can model all the methods of residual allocation.

Requested data
For every transformer connecting a load or generator to Transpower's network (this should include every connecting transformer regardless of whether Transpower owns the transformer or not), the following information:

- Transpower’s designation (or owner’s if applicable)
- Owner
- Primary GXP/GIP
- Secondary GXP/GIP (if applicable)
- Nominal capacity
- Operating capacity (if applicable)
- AMD peak demand on the transformers

Appreciate you’re on the road this week conducting briefing workshops, but if you could please advise initially whether this information can be provided and the likely timing to do so.

7. Oji Fibre (previously Carter Holt Harvey)

Authority responses in red

Below are some questions on your second TPM issues paper.

I will be attending the workshop in Wellington in the afternoon of Wednesday 15th June and would like if possible to discuss these questions with you between 8.30 and 10 if that was suitable to you. Could you please advise if this is suitable.

1. Basis for allocating residual

a. Did the EA consider adding a time dimension to the historical demand which would produce a measure more reflective of the actual load profiles that have generally determined the shape and size of the existing grid? ie using historical RCPD as a measure?

The residual charge is proposed to be a capacity-based charge on load. It should be noted that while the Authority modelled the residual charge based on gross anytime maximum demand (AMD), the draft TPM guidelines provide for Transpower to consider either gross AMD, line capacity or transformer capacity as options for measuring capacity. The Authority sought a design for the residual charge that meant it was difficult to avoid, and therefore would reduce incentives to inefficiently alter use of the grid to avoid the charge, which is why the Authority proposed it be allocated according to historical physical capacity. Physical capacity also provides a reasonable reflection of a customer's demand for transmission services.

A reason for proposing physical capacity rather RCPD is that with the latter there is a risk that for some customers their charges may be below the incremental cost of supplying them with transmission services. This is because they are largely able to avoid the interconnection charge under the status quo. If a customer's transmission charges were below incremental cost, this would mean other users were cross-subsidising the costs of supplying the customer with transmission services, which would be inefficient. Historical RCPD would not avoid this potential problem.

b. Why has the EA proposed three quite different potential residual allocation bases which may have significantly different outcomes for some consumers?

The Authority proposed three different potential bases for allocating the residual charge as they are all possible ways for calculating physical capacity, which as noted above provides a reasonable reflection of a customer's demand for transmission services. Each method has advantages and disadvantages, which would need to be considered in selecting a preferred approach. Transpower has access to the detailed information that may be relevant to this, which is why the proposal provides for Transpower to propose method that is adopted. The method that Transpower proposes would need to be the method that best advances the Authority's objective, while being consistent with the guidelines and Part 4 of the Commerce Act.

c. The modelling seems to have been done based on demands at individual GXPs rather than demands at nodes where there are sometimes more than one GXP. It would seem more appropriate to assess demand for grid capacity at nodes rather than GXPs. Was modelling based on nodes considered?

It is correct that the Authority's modelling of demand is determined at individual GXPs, which the Authority considers is a reasonable proxy for physical capacity. The proposed guidelines do not specify the level of granularity to which demand would be calculated if the residual charge were calculated on an anytime maximum demand basis. This is a matter that would be proposed by Transpower in its development of the TPM.

d. The explanation in para 118 is not entirely clear to me. Can we discuss?

The Authority's proposal is to apply gross rather than net AMD. Under gross AMD, for the trading period by which AMD applies, Transpower would calculate volumes of distributed generation (DG), demand-side management and demand response undertaken during that trading period and add that to the net AMD. For example, if net AMD at a GXP was 100MW but a DG connected behind that GXP generated at 10MW during that AMD period, the gross AMD would be 110MW.

The "threshold for a minimum size…" is included to provide a materiality threshold whereby if quantities of distributed generation (DG), demand-side management and demand response during the AMD period are below a certain threshold then they would not need to be included in the gross AMD calculation.

We would be happy to discuss this further with you if you wish.

2. Nodal pricing as an indication of need for investment.

a. Are there any historical examples that the EA knows of that illustrate the EAs view that in general nodal price variations have been sufficient to signal the need for new investment?

The Authority is not in possession of actual examples. The Authority considers that nodal pricing is an important driver of efficient investment but that nodal prices are insufficient on their own to promote efficient investment. For example, reliability investments are not required to exhibit net benefits. The Authority has provided as an additional component for Transpower to propose a LRMC charge to defer investment if that would be efficient.

3. Please provide some data to support the EA view that RCPD signal is poorly correlated with times when the grid is congested (Para 66)

The Authority's view is that parties in the upper North Island take action to avoid RCPD peaks whereas there is no congestion in the upper North Island and peak avoidance does not reduce transmission costs. Transpower's operational review of the TPM has confirmed this view and this led to Transpower proposing to change the number of peaks in the RCPD charge in that region. Please refer to pages 52 to 65 of the TPM second issues paper for a discussion on this.

4. What change do you think there would be in our charges if the Arapuni split is open (as seems very likely to be the case in the future)?

The "Arapuni bus-split net benefit test, June 2016" (refer https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/Arapuni%20Bus-split%20Net%20Benefit%20TestJune2016.pdf) assesses the cost and benefits of a number of options. The study supports Option 3: "keeping the Arapuni 110 kV bus-split and implementing the Arapuni–Kinleith generation runback scheme and VLR on the Kinleith– Tarukenga circuits." The benefits of Option 3 are described as coming from three sources: dispatch, losses, and reduced unserved energy. According to Transpower, the runback scheme and VLR will remove the risk of a pre-contingent constraint on South Waikato load when the largest generating unit in the region (Kinleith co-generation) is unavailable. Option 3 has a capital cost of $0.7m and total benefits are assessed by Transpower as being $1.2m–providing for net benefits of $0.5m to 2022.

The Authority has not undertaken an assessment of the beneficiaries of this investment. However, under the TPM proposal, the costs would be recovered through the “simplified” area-of-benefit charge, ie, it is an investment with a total cost of less than $5m. Refer paragraph 8(b) of the proposed TPM guidelines. Transpower would be responsible for identifying and quantifying the beneficiaries. Oji Fibre would have the option of engaging with Transpower in relation to the investment including its assessment of beneficiaries.

5. Does optimising encompass the possibility of optimising grid assets in the residual portion?

Optimisation is intended to be available for area-of-benefit assets only. The proposed prudent discount policy is the proposed mechanism for addressing inefficiencies resulting from the residual charge. Refer paragraphs 34 to 42 of the proposed TPM guidelines.

6. Assuming no optimisation, could you please provide an estimate of the materiality of the likely increase in AOB assets over the next ten years? (para 121)

Given the proposed area-of-benefit charge applies to all future investments commissioned on or after the date the TPM guidelines are confirmed, all new capital expenditure would be included in the area-of-benefit charge. However, this would be offset by the depreciation of existing assets. Note that for the purposes of charging, existing assets are proposed to be valued according to depreciated historical cost (DHC). For new assets, Transpower is afforded flexibility to determine whether assets should be valued at replacement cost or another method such as DHC. The Authority has not determined how quickly the area-of-benefit charge would increase. This would depend on the quantum of capital expenditure and the depreciation of existing assets. Oji Fibre’s area-of-benefit charge would increase to the extent it was determined to benefit from new investments. However, where replaced assets move through to the area-of-benefit charge, the residual charge would likely reduce. The area-of-benefit charge might also reduce, due to optimisation. This would have the effect of increasing the residual charge.

7. Prudent discount

a. Does the EA consider that there may be some potential overlap between the ability to adjust the residual charge allocation measure (7.183 and 7.185) and a prudent discount via 7.253 etc. ?

Paragraph 39(b) of the proposed TPM guidelines requires prudent discounts to remain under review. Where circumstances change, a prudent discount may be adjusted or discontinued. If (say) a “7.185 material change in circumstances” resulted in reduced charges, it may be appropriate to review relevant prudent discounts, but this would be a matter for Transpower in its development of the TPM, should the Authority decide to confirm the proposed guidelines.

b. This situation could readily arise in any future plant changes at both Kinleith and Tasman.

The Authority would welcome descriptions of such situations in your submission.

8. Area of benefit charges

a. While the concept of applying the charges to all who benefit seems clear, I don't understand the example given in 7.92 regarding the improvement in CNI load from the NIGU project.

The Authority understands that NIGU may have provided improved reliability in the central North Island through, for example, reducing the risk of constraints occuring. It is important to note though that a customer would only pay area-of-benefit charges in relation to an investment if it was expected to receive net benefits over the lifetime of the investments (ie, if benefits less dis-benefits were positive). Accordingly, even if central North Island benefited from improved as a result of NIGU, central North Island load would only be charged for NIGU if these benefits exceeded any disbenefits, eg increased nodal prices relative to the situation without NIGU.

The Authority applied the vSPD model to quantify the beneficiaries of NIGU although Transpower could opt for a different approach. Please refer to the excel file titled "Results_20160517b" sheet: "Charges to part by investment" for a detailed breakdown of the beneficiaries and allocated charges for NIGU under the modelling of the proposal. This is available at: http://www.emi.ea.govt.nz/Datasets/Browse?directory=%2FResults_spreadsheet&parentDirectory=%2FDatasets%2FSupplementary_information%2F2016%2F20160517_TPM_second_issues_paper. Note that upper North Island loads along with generators are identified as the main beneficiaries of NIGU under the modelling.

b. It seems quite possible that using a physical capacity measure to determine allocation of area of benefit costs would result in an inequitable distribution of costs which might lead to durability issues. Why is the EA including this as an option for Transpower to consider?

The Authority's proposal provides for physical capacity to be used as an allocator under the area-of-benefit charge among load beneficiaries within an area-of-benefit (eg at a node) if it is not practicable or efficient to allocate charges on the basis of net benefit. The allocation between areas of benefit would be on the basis of net benefit only. Accordingly, the Authority expects that the bulk of area-of-benefit charges would be allocated on the basis of net benefit, so does not consider that there is a major issue with durability to the extent that physical capacity is used as an allocator for the area-of-benefit charge.

c. How would the EA expect that TransPower would define the area of benefit in this case?

Note that the Authority has overall responsibility for approving the TPM once it is proposed by Transpower. The Authority proposes that areas of benefit are defined to as granular a level as practicable. The Authority's preference is for approaches that most effectively approximate expected net benefits, bearing in mind administration costs.

Lastly, the Authority invites you to address all points in your submission.

8. Frizzell Ag Electronics

Authority response

The Authority has proposed TPM guidelines. If the Authority confirms its proposed guidelines it is Transpower's responsibility to develop a transmission pricing methodology (TPM) that is consistent with the TPM guidelines. The Authority is then responsible for approving Transpower's proposed TPM. It is important to bear this in mind because detail that may impact on the quantum of a party's charges would need to be developed by Transpower, and so while the Authority has modelled its proposed TPM charges, the results are indicative only.

The proposed TPM, as outlined in the Authority's TPM second issues paper,[1] provides for three principal charges: retention of the existing connection charge, an area-of-benefit (AoB) charge and a residual charge.

Area-of-benefit charge

The proposed area-of-benefit charge recovers the costs of recent large transmission investments and future investments.[2] It is intended to be calculated on the basis of expected net benefits.[3] While the Authority has not specified how expected net benefits would be calculated, it has estimated charges using the vectorised Scheduling, pricing and dispatch (vSPD) model (which is similar to the model used to operate the wholesale electricity market). The Authority modelled Electricity Ashburton (EA)'s area-of-benefit charge to be $720,000 pa. Note that this charge may increase in the future where Transpower undertakes new transmission investments and where, in applying the AoB charge, it assesses that EA is expected to benefit from these investments.

The area-of-benefit charge is intended to provide a price signal to promote efficient transmission investment at the time Transpower is considering transmission investments or non-transmission solutions.[4] (Non-transmission solutions encompass activities such as distributed generation or demand response.) Parties that can reduce their level of expected benefits of a proposed investment will face lower charges than they would otherwise. Alternatively, Transpower can contract directly with providers of non-transmission solutions to reduce transmission costs. The costs of non-transmission solutions would be recovered through the area-of-benefit charge.[5]

Residual charge

Under the Authority's proposal, indicative modelling suggests EA's main exposure to transmission costs is through the proposed residual charge. The residual charge

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[1] Available on the Authority's website at: http://www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/consultations/#c15999.

[2] Refer to paragraph 7 of the proposed TPM guidelines attached in appendix A of the TPM second issues paper.

[3] Refer to paragraph 9(b) of the proposed TPM guidelines.

[4] Non-transmission solutions are provided for under the Commerce Commission's capital expenditure input methodologies.

[5] Refer clause 7(d) of the draft TPM guidelines.

recovers Transpower's revenue that is not recovered through other charges – mainly, the connection charge and the area-of-benefit charge. The Authority's indicative modelling of its proposal indicates the residual charge would be the major transmission charge initially faced by EA ($11.32m pa of total $12.73m pa).

The residual charge is intended to be a capacity charge on load. Please refer to paragraphs 23 to 31 of the proposed TPM guidelines for a description of the proposed residual charge. The Authority has sought to design the residual charge so that is difficult for parties to avoid. Avoidance of this charge would be inefficient as it just shifts costs onto other parties rather than reducing costs overall.

The Authority proposes three approaches for determining a party's capacity–line capacity, transformer capacity and "gross" anytime historical demand (AMD). All would be calculated on a historical basis, so a reduction in demand would not reduce charges (except in the long term, as the proposal includes an adjustment to the calculation of the residual charge on a lagged basis, eg 10 years). The Authority modelled the residual charge based on gross AMD although (if the Authority confirms its proposal) Transpower could potentially develop the TPM using one of the other methods.

Gross AMD means that "electricity generated by generation connected to the customer's network…[and] the volume of demand-side management and demand response on the customer's network" is added to volumes of electricity taken from the grid for the purpose of determining AMD. As such photovoltaic and battery systems would not reduce gross AMD.

Further, as noted above, it is proposed that, as with the other measures of physical capacity, gross AMD would be calculated on a historical basis, in this case the previous five years' AMD. It is not future looking. Therefore, if EA reduces its AMD to 100MW this would not reduce its historical gross AMD.[6]

Note that photovoltaic and battery systems could however potentially reduce or avoid the need for future transmission investment, and therefore avoid or reduce area-of-benefit charges that would be used to recover the costs of this investment.

It is important to note that the Authority has not confirmed its proposal and will consider submissions on the TPM second issues paper, due 26 July 2016. The Authority invites all interested parties to make a submission.

<u>Question</u>

For EA Networks given their summer/12 month peak is about 180MW under the new pricing system as a general principle, if they were able to reduce this to say 100MW would they get a proportional decrease in Transpower charges or would because Transpower has 180MW of installed capacity they would still have to pay the charges for 180MW ?

[6] Refer paragraph 25 of the draft TPM guidelines.

9. Northpower (2)

Authority response (1 and 2) are provided below in red.

In reviewing my previous email, I note that I made mention of “Winstones”. While we have sites here that are identified as “Winstones”, the very large industrial site to which I was referring is actually identified as a “Fletchers” site. Looking at the web, I note that Winstones was acquired by the Fletcher group of companies several decades ago, so I am now even less clear as what the EA might have included in the “Winstones” group in the issues paper.

I look forward to hearing from John with clarification on these issues.

1

The customer is Winstone Pulp International located near Ohakune rather than Winstone Aggregates.

2

It would be helpful if you would refer this to someone in your organisation who could respond to me regarding the “status quo” figures in Table 10 and Table 11 towards the end of the document please.

In order to consider the impact of the EA’s proposal on the consumers supplied by the Northpower network, I need to look at the impact on each of the major consumer groups: Very Large Industrial (VLI), Commercial & Industrial (C&I) and mass-market.

However, when I compare the existing transmission charges (effective 1 April 2017) with the figures in those tables for “status quo”, there is a significant difference (in millions of dollars) so I suspect I am not comparing “apples with apples”.

The calculation of charges is indicative only. The calculation is based on 2014 demand data with growth projections of 1% per annum (with a few exceptions which do not apply to Northpower). The calculated charges are projected for the 2019 calendar year. The status quo calculation is based on the changes from Transpower’s TPM operational review being in place, namely, the move to 100 peaks for the RCPD charge in the upper North Island and upper South Island regions. The status quo calculation is designed to be comparable to the Authority’s proposal, so that parties can assess the impact. Accordingly, the status quo calculation does not always accurately reconcile to current actual charges. Status quo charges are expected charges for the 2019 calendar year if the Authority does not change the TPM guidelines.

- Clause D7 notes that the results are “net of LCE”. Does that imply that the credits that distributors currently receive for Loss & Constraints have been subtracted from the transmission charges paid to Transpower to yield the figures in Tables 8, 9, 10 and 11.

The figures in Tables 8, 9, 10 and 11 are calculated by subtracting estimated forecast LCE from the total revenue requirement for both the status quo and proposal before calculating individual customers' estimated charges so the charges are not based on actual LCE paid to distributors and other parties under the status quo. The treatment is the same for the status quo and proposal scenarios to provide a 'like-for-like' comparison. LCE was calculated at $50m ($45m for HVAC and $5m for HVDC).

- Have existing Connection Charges included in the figures in Tables 8, 9, 10 and 11? Or are the figures only for the existing Interconnection Charges.

Connection charges are excluded from these tables.

- I note that the figures for the refinery are shown separately in Tables 10 and 11. Clause D10(b) notes that some industrial consumers have been separated out even though they pay their transmission charges to a network, which is the case for the refinery (Refining NZ pays their share of transmission charges to Northpower since the site is supplied from the Northpower network). So, does that mean the that figures shown for "Northpower" have had the refinery charges subtracted?

The refinery charges have been subtracted from Northpower's total because the refinery had previously requested an assessment of charge their charges. We advised them at that time that the allocation is indicative only and that the actual charges were a matter from Northpower. Northpower's total calculated charges would be Northpower charges plus the Refinery charges.

- Other industrials including CHH and Winstones are listed in Tables 10 and 11. Do those represent specific sites for those companies, or the sum of all their sites across NZ? We have two large industrial sites owned by CHH and a very large site owned by Winstones supplied from the Northpower network and those companies pay transmission charges to Northpower (directly in one case and via a retailer in the other case).

Winstone Pulp International charges are based on their load at the TNG0111 node, which is at Tangiwai. The refinery is the only customer that has been split out from Northpower. For Northpower's total charge, please add back the refinery charge for the proposal and status quo scenarios.

- I note that clause D11 states that ACOT payments have been excluded from the tables. Can I assume that applies for both the "status quo" and the "proposed"?

We confirm that the modelled charges in Tables 10 and 11 for both the status quo and proposal scenarios are exclusive of ACOT payments. The treatment is the same for both scenarios.

10. Buller

Authority response in red

It was good speaking to you yesterday. As discussed, I asked our modellers to consider your points. I have detailed our response below to each point you raise (in blue text), after a general introductory paragraph.

It is important to recognise that the modelling is indicative impact modelling. It is based on a number of assumptions, which require a level of judgement. Secondly, Transpower will have responsibility for determining the transmission pricing methodology (TPM) consistent with the TPM guidelines. The Authority is responsible for developing the guidelines. The draft guidelines provide Transpower with a degree of discretion and flexibility to develop approaches that best meet the guidelines. Therefore, it is possible that Transpower will recommend approaches to some matters which are different than the approach used for modelling purposes, and this may mean actual charges differ somewhat from the indicative charges that have been modelled.

The points of interest to you and our responses are as follows:

1. At this stage we are not able to reconcile the figures in Appendix D (Tables 10 & 11) for the Status Quo case with what we know to be our transmission charges. We need some more information on how the figures were determined to ensure we are understanding them correctly and/or confirm an error has been made. From what source were the status quo transmission charges obtained?

   The modelling was based on 2014 electricity market data that has been scaled, taking into account demand growth and a few new transmission investments to represent a 2019 scenario.

   The modelling was generally done on the basis of gross AMD. The gross aspect means adding demand response and DG production to the offtake at the distributor grid injection points. However, in Buller's case these are actual AMD's (not gross AMDs) because the modellers didn't have generation data for small embedded (distributed generation) plant within Buller's network. In reality, then Buller's gross AMD may be slightly higher than actually modelled for.

   Given that Buller is likely to have access to the embedded generation data, you could recalculate the 'gross AMD' allocator, and then scale your residual charge by the factor (2014 gross AMD / 2014 net AMD) to estimate the effect the embedded generation will have (2014 being the year the base data was derived from).

   You suggest that the indicative modelling shows status quo charges that are "substantially below" what Transpower charges (i.e. Tables 1 and 2 in your note). Please note that the major discrepancy relates to the fact that the modelled indicative status quo charges exclude connection charges. The indicative status quo charges of \$1.3m/yr compare favourably with Buller's 2015/16 interconnection charge of \$1.3m/yr.

2. In addition, a large industrial consumer (which we understand the energy consumption for which was included in the calculation of the $/MWh value of indicative charge) will cease operation at the end of June 2016 **[Information removed]**. This will cause a major drop in our existing transmission costs and also change our indicative charges. In order for Buller Electricity to understand how the proposed TPM will impact its post June 2016 situation it will be necessary for some addition modelling results to be made available.

   The modellers indicated that they could not reliably separate out Holcim's demand from that of Buller network, and therefore the modelling was undertaken with the data as it was, rather than using judgement to arbitrarily modify it. The reasoning being that this would produce indicative modelling that was more understandable and consistent. Therefore, we do not know what your charges would be under the current TPM methodology if Holicim or another major customer on your network left.

   The proposal is that residual charge will be based on the capacity of the transmission load customer at the time of releasing the TPM second Issues Paper – 17 May 2016. Moving forward, it will be adjusted over time using a ten year lag. Therefore, under the proposal, the residual charge would not be affected within the first ten years by a reduction in capacity, that could in Buller's instance be brought about by a departure of a major customer. However, as Carl Hansen discussed with you, we are interested in feedback on this particular issue.

   The proposal includes that the area of benefit charge can be readjusted if there is a material change in circumstances. The exit of a major industrial customer like Holicim could amount to a material change in circumstances. Therefore, the area of benefit charge could be adjusted down for Buller. I realise that this only is modelled to make up an initial 9% of your transmission charges. The modellers have indicated that to 'adjust' the AoB component of Buller's indicative charge to reflect Holcim's exit, Buller could scale the AoB charge by the energy ratio after/before Holcim's exit. While imperfect, scaling your AoB charge in this way should give a reasonable indication of Buller's likely AoB charge, since the AoB charge is a small proportion of your overall charges (about 9%).

3. Are you able to tell us what value of historic AMD which was used to determine Buller Electricity's Residual Charge?

   The indicative gross AMD's used to calculate Buller's residual charge are:
   - ORO1101 9.4MW
   - ORO1102 9.6MW
   - WPT0111 9.4MW

   As discussed above they were for the 2014 pricing year.

<u>Questions</u>

In a meeting Buller Electricity had this morning with the EA, Carl Hansen mentioned that we should get in contact with you to provide answers to some questions we have regarding the indicative charge results presented.

The 3 main points which are of interest to us are outlined as follows:

1. At this stage we are not able to reconcile the figures in Appendix D (Tables 10 & 11) for the Status Quo case with what we know to be our transmission charges. We need some more information on how the figures were determined to ensure we are understanding them correctly and/or confirm an error has been made. From what source were the status quo transmission charges obtained?
2. In addition a large industrial consumer (which we understand the energy consumption for which was included in the calculation of the $/MWh value of indicative charge) will cease operation at the end of June 2016 **[Information removed]**. This will cause a major drop in our existing transmission costs and also change our indicative charges. In order for Buller Electricity to understand how the proposed TPM will impact its post June 2016 situation it will be necessary for some addition modelling results to be made available.
3. Are you able to tell us what value of historic AMD which was used to determine Buller Electricity's Residual Charge?

We prepared some notes prior to the meeting for our own benefit and these are attached. Section 2 provides the 2015/16 transmission costs against which we are trying to reconcile the indicative charges in the EA Paper. 2016/17 transmission charges were not included due to the significant changes which are happening to the load in June 2016, however the pre-change annualised 2016/17 transmission costs can be provided if required.

11. Buller 2

Authority responses in red.

I have the following comments:

- Holcim load represents over 90% of the load at the WPT GXP. For modelling purposes it can be assumed that all of the load at the WPT GXP is attributable to Holcim.
- There is very little difference between gross AMD and net AMD at the ORO GXP, so accounting for this will not greatly change our charges under the proposal.
- The AMD figures stated below for ORO1101, ORO1102, WPT0111 seem about right and in recent years have consistently been in the 9-10MW range.
- In Appendix D Table 10 do both the Status quo (Post 2017 TPM) and Proposal figures of $1.277M & $1.79M exclude Connection Charges? Correct, connection charges are not included in Table 10.
- Why is the terminology (Post 2017 TPM) used? What is the significance of this term? This refers to the TPM following changes from Transpower's 2015 operational review.
- The summation of the AMD's given for ORO1101, ORO1102 and WPT0111 gives a total of 28.4MW. Correct. See attached spreadsheet. **[Information removed]** Assuming that our AoB Charge is 9% of our initial charge of $1.79M. Correct, this allows a Residual Rate of $57.35 per kW of AMD ($1.79M * 0.91 / 28.4MW) to be calculated. Is the basis of this calculation sound? Yes.

In terms of the methodology used to determine BEL's indicative charges under the proposed TPM, there are 2 major factors which BEL has identified which appear to significantly disadvantage us.
These factors related to our specific (and unusual) circumstances as follows:

- Supply from the WPT GXP will be discontinued at the end of June 2016 with only a small proportion of the load being transferred to the ORO GXP. The remaining WPT GXP load will cease. In this situation would it be the intention that BEL's Residual Charge be determined including or excluding the WPT GXP AMD? It seems particular unfair if it were to included WPT GXP AMD as BEL consumers would have to pay for a load that has disappeared for a further 5-10 year period (depending on the exact method which is decided upon to determine historic AMD/capacity). In BEL's view the methodology for determining the Residual Charge (via AMD or otherwise) needs to include a provision allowing for the adjustment of the Residual Charge allocation factor (AMD, capacity etc) if large changes in load occur (upwards or downwards). Obviously reductions in a distributors load by 50% are very uncommon. There is an intentional lag in the calculation of AMD to avoid inefficient behaviour to avoid charges. We acknowledge the issues that arise from the departure of most of the load at the WPT GXP and we invite Buller to address this in its submission.

- BEL takes supply at the ORO GXP at 110kV (we own the 110/33/11kV Robertson St Substation) and as a result there are 2 GXPs e.g. ORO1101 & ORO1102 recorded in the electricity market. During periods of Inangahua to ORO/WPT GXP 110kV line outages (planned or unplanned), or when BEL undertakes Robertson St Substation maintenance, all of our load is supplied from the ORO1101 or ORO1102 GXP. So while our total ORO GXP AMD (determined from the half hour by half hour addition of ORO1101 & ORO1102 loads) is in the 9-10MW range, in terms of the modelling work which has been done it appears that the Residual Charge at the ORO GXP has been determined using an AMD in the 18-20MW range e.g. the addition of the GXP AMD's. Are you able to confirm this is the case? Yes, we confirm this is the case. This would mean that BEL's Residual Charge for the ORO GXP would be double compared to the situation where the Robertson St Substation was a Transpower owned substation and BEL took supply at 33kV and 11kV. BEL clearly sees this as being unfair and would advocate that in situations like the one described the AMD for the GXP needs to be determined from the half hour by half hour combined GXP loads (as is currently done for determining RCPD) rather than the summation of the individual GXP AMD's. We note the argument for aggregating nodes in certain circumstances and invite Buller to address this point in its submission.

BEL would hope that the 2 factors described above are clearly recognised as being unfair, and at this stage can be considered as being modelling over sites which would be rectified in the final implementation of a new TPM. How these factors are dealt with will however have a very material impact of BEL's transmission charges under the proposal. As a result it would be helpful if the EA could provide comment on these factors so that BEL can have some confidence that we are correctly accessing the impact on the proposed TPM on our transmission charges. As noted above, we acknowledge the issues you have raised with respect to calculation of the residual charge and we invite you to address these matters in your submission. Please note that in relation to this point and the one above, matters of fairness are not a matter that the Authority is permitted to take into account in making a decision. The Authority is restricted to promoting its statutory objective – competition, efficiency and reliability for the long term benefit of consumers.

Under the circumstances that:

- BEL's Residual Charge excludes any historic AMD contribution from the WPT GXP & Holcim
- The combined AMD for ORO1101 & ORO1102 is assessed as being in the 9-10MW range e.g. we are not double charge because of our unusual supply/substation arrangement
- Assuming that our initial AoB Charge remains unchanged at 9% of $1.79M e.g. $0.161M

I determine that our combined Residual Charge + AoB Charge would be approximately 9.5MW * $57.35 + $161k = $0.706M. Please refer to the sheet labelled "proposed Buller residual" in the attached excel spreadsheet. **[Information removed]** If you insert a gross AMD number into cell C4, column H will calculate a revised residual charge for Buller. It should be noted that the Authority has not come to any decision on adjusting the residual calculation from that presented in the TPM second issues paper. The Authority will however, consider all submissions. Is the basis of this calculation sound and realistically represent the intended implementation of the proposed TPM?

It is noted that Connection Charges would be in addition to the $0.706M. Correct.

12. Buller 3

Authority response

The Authority understands that the ACOT calculation varies from distributor to distributor. This is possibly due to fact that ACOT is administered through pricing principles rather than a prescriptive methodology. Therefore, it is not always possible to accurately determine how the principles will be interpreted. Many distributors however, base their calculation of ACOT on avoided transmission charges.

The proposed residual charge has been designed to be difficult to avoid. It is proposed to be based on historical physical capacity (lines, transformers or gross anytime maximum demand (AMD)) with distributed generation (and demand response) being added in. It is therefore unlikely that a distributed generator (DG) would be able to show that it is enabling a distributor to avoid part of its residual charge.

It might be possible, however, for a DG to establish that it has enabled or, in the case of new investments, will enable a distributor to avoid some future area-of-benefit charges. Their ability to do this would be based on providing evidence that the DG has reduced or will reduce a distributor's expected net benefit in relation to a transmission investment or would defer or avoid the need for a future transmission investment that the distributor would pay area-of-benefit charges for. Their precise ability to do this would depend on the methodology that Transpower employed to quantify net benefits.

In addition, if the LRMC additional component were implemented, a DG may be able to assist in lowering or avoiding LRMC charges faced by a distributor.

Further, when Transpower is considering a new transmission investment, a DG or DGs could propose a non-transmission solution to Transpower. Transpower is required under the Commerce Commission's input methodologies to consider alternatives to transmission investments. Accordingly, DGs can seek payments directly from Transpower for avoiding or postponing a transmission investment (or part thereof).

Please note that the Authority has not made its decision on the TPM or the distributed generation pricing principles. The Authority will consider submissions before making any decisions.

Question

Thanks for the previous response to the questions BEL raised.

One further question:

With regard to the existing ACOT payments to distributed generations, if the proposed TPM guidelines were adopted and the existing ACOT payment regime was retained, how would the ACOT be determined? I presume it would no longer be

determined using RCPD, but rather on the basis of the proposed AoB and Residual charging mechanisms. But under the proposed TPM guidelines it appears that there would be no ACOT because the proposed allocators cannot be reduced by distributed generation e.g. Gross AMD.
Any comments or feedback?

13. David Reid at P2P (2)

Authority responses in red

Metric	Appropriate indicative assumption	Source of assumption
Annual revenue required to cover CAPEX (revenue/Capex ratio) at current WACC	XX %pa	Transpower's total regulated revenue requirement is the starting point. This sets the maximum return for all regulated assets and to which the TPM applies. Note that Transpower has assets that are not revenue regulated such as those covered by customer investment contracts (CIC). The costs of these assets are not recovered through the TPM. The annual forecast revenue of $970.6 million less $265 million of operating expenses, provides the total revenue required to fund the capital cost of capex. This is $705.6 million. Note the annual forecast revenue is based on Transpower forecasts for 2019/20. For the TPM options working paper, the Authority's calculation of the annual revenue of assets was 15% of commissioned value. This was on the basis that annual revenue for assets only needed to be calculated for large and recent investments. Submissions on the Authority TPM options working paper informed the Authority that 15% was not a robust assumption. For the TPM second issues paper the Authority requested annual revenue information directly from Transpower. The information provided by Transpower included a provision for maintenance and operating expenses. The information was only required for the investments included in the area-of-benefit charge. This is because assets allocated to the residual charge essentially form an unallocated pool. The total revenue required less what is recovered through other charges, is recovered through the residual. The following provides a breakdown of Transpower's forecast revenue for the 2019-20 pricing year.

<table>
<tr><td></td><td></td><td>
<table>
<tr><th></th><th>Area-of-benefit</th><th>Residual charge</th><th>HVDC</th><th>RCPD</th><th>Connection</th><th>LCE</th><th>Total ($m)</th></tr>
<tr><td>Status quo (May 2016 update)</td><td></td><td></td><td>140</td><td>656</td><td>125</td><td>50</td><td>970.6</td></tr>
<tr><td>Proposal (May 2016)</td><td>296</td><td>500</td><td></td><td></td><td>125</td><td>50</td><td>970.6</td></tr>
</table>
</td></tr>
<tr><td>Indicative average Grid CAPEX expected to be invested per annum for asset renewal and new builds from 2019</td><td>$970.6 million less $265m = $705m.</td><td>There is uncertainty around future capex. Transpower acknowledges this in its ‘Transmission Tomorrow’ presentation now available on Transpower’s website. Transpower publishes an excel file titled “RT06 - Integrated Transmission Plan” that contains CAPEX projections in an easy to manipulate form. The file is available at: https://www.transpower.co.nz/node/10951/regulatory-templates.
From the above referenced file, at a high level, major capex is estimated to be around $100m pa with base capex (including renewals) typically around $240m pa. Note the forecasts only runs through to 2024-25.</td></tr>
<tr><td>Book value of Grid Assets excluded from AoB consideration (excluding post 2004 upgrades over $50m and pole 2)</td><td>$4,635 million less $2,336m less $785m = $1,514m.</td><td>The following provides a list of assets included in the area-of-benefit charge as at 29/2/2016. The revenue requirement for each asset (based on Transpower information) is included.
<table>
<tr><th>Area-of-benefit asset</th><th>Net Book Value as at 29/2/2016</th><th>Revenue Requirement</th></tr>
<tr><td>NIGU</td><td>826.4</td><td>85.3</td></tr>
<tr><td>HVDC (Poles 2 and 3)</td><td>734.0</td><td>118</td></tr>
<tr><td>NAaN</td><td>334.2</td><td>39.2</td></tr>
<tr><td>LSI renewables</td><td>28.5</td><td>4.2</td></tr>
<tr><td>Wairakei Ring</td><td>132.3</td><td>14.8</td></tr>
<tr><td>Otahuhu GIS</td><td>91.0</td><td>12</td></tr>
<tr><td>BPE-HAY</td><td>53.0</td><td>5.5</td></tr>
<tr><td>USI reactive support</td><td>33.0</td><td>3.5</td></tr>
<tr><td>UNI Dynamic reactive support</td><td>53.0</td><td>5.5</td></tr>
<tr><td>LSI Reliability</td><td>14.0</td><td>2.1</td></tr>
<tr><td>Wanganui-Stratford</td><td>13.9</td><td>2.08</td></tr>
<tr><td>ISL-KIK new 220kV circuit</td><td>18.5</td><td>2.770</td></tr>
<tr><td>Other</td><td>4.5</td><td>0.67</td></tr>
<tr><td></td><td></td><td></td></tr>
<tr><td>AoB assets</td><td>2,336</td><td>295.62</td></tr>
</table>
Net book value of connection assets: $785m.
Net book value, all regulated assets: $4,635m
Net book value of assets excluded from the area-of-benefit charge and connection charge: $1,514m.</td></tr>
</table>

		The estimate for the residual charge is calculated by subtracting the above ($296m), connection charges ($125m) and loss and constraint access ($50m) income from Transpower's total revenue requirement (of $970.6m) Note: The Authority did not require asset level regulated asset base (RAB) information to develop its proposal.
Indicative average depreciation rate of Old Asset excluded from AoB consideratio n	XX %pa	The Transpower regulatory report available at the hyperlink below provides total depreciation for all regulated assets. Transpower applies straight line depreciation to its assets. Available at: https://www.transpower.co.nz/sites/default/files/publications/resources/Annual%20regulatory%20report%202014-15.pdf
Indicative Annual O&M that could be attributed to Assets excluded from AoB consideratio n – as a percentage of annual Capex contribution	XX %pa	As stated above, the Authority did not need to prepare a separate split. However, the RT06 file referred to above provides an operating expenditure budget to 2024-5. Total operating expenses (including maintenance and overheads) are around $265m pa. It is important to note that separate splits for O&M are not currently provided. This is because of the way the current TPM works. O&M is required to be calculated for connection assets only and there is an allocation mechanism in the connection charge. There is also a requirement to allocate maintenance and operating expenses to the HVDC. The existing interconnection charge (the regional coincident peak demand or RCPD charge) is a residual whereby anything not captured by HVDC or connection is allocated by this charge. There is no requirement, for example, to determine the actual cost of maintaining individual interconnection assets. Note the Authority's proposal requires Transpower to develop a methodology for allocating maintenance and operating costs to area-of-benefit assets. The proposal also requires Transpower consider implementing an actual cost-based methodology for allocating O&M to connection and area-of-benefit assets. The Authority approves the TPM so the Authority will consider, consult on and approve matters that Transpower is required to develop

		under the TPM guidelines.
Indicative Annual O&M that could be attributed to Assets included in AoB consideration – as a percentage of annual Capex contribution (if different from older assets)	XX %pa	Please refer above.

Authority responses in red

Based on this and a reading of the OGW document, my understanding of the EA's view and CBA is as below. Could you please confirm I have this right?

- The status quo assumption is a HVDC SIMI charge of $150m pa applies to SI generators and it is not able to be passed on

The methodology does not explicitly assume that generators cannot pass this on.

- Under the TPM proposal, SI generators will no longer be required to meet the full HVDC costs, rather only their share of the AoB charge, which indicatively has been estimated at $53m/y. The balance will be met by Load.

Yes, that is correct. The total area-of-benefit charges modelled for generators is $63.78m. This is not inclusive of generators' connection charges. Generators also incur residual and overhead charges of $5.88m (to the extent that they are seen as load).

- The CBA estimated the NPV of the proposal to discontinue the SIMI charge as indicatively $13.7m over 20 years based solely on the effect of removing the disincentive to build cheaper SI generation in the future.

Yes, that is correct.

- The EA/OGW do not consider there is an economic cost of the SIMI charge being passed through to Load, resulting in a $100m/y wealth transfer to SI generators from Load and the associated increase in the total delivered cost of electricity by the same amount.

The methodology does not recognise wealth transfers.

- The EA does not consider a $100m/y wealth transfers to SI generators from Loading to be a durability problem.

This is not considered in the CBA methodology.

Appreciate if you can confirm or correct my understanding.

14. General information regarding TPM modelling for David Reid at P2P

Authority response

I thought it would be useful to follow-up in writing to summarise our phone discussion regarding the TPM modelling.

As per our discussion, I understand that you had three main queries:

- How the ‘transmission investment’ revenue requirements were established;
- How LCE is treated; and
- Explaining why there are two different methods used to allocate transmission investments.

Transmission investment revenue requirements

The revenue requirements for each transmission investment were determined from information supplied by Transpower. The HVAC investment revenue requirements are made up of a capital charge and an O&M component. The Pole 2 and Pole 3 investment revenue requirements also includes an overhead component (as well as the capital and O&M). The total Pole 2 and 3 annual revenue modelled under the proposal is $118m.

As discussed, this differs from the RCP2 forecast HVDC revenue requirement of $139.7m (i.e. $144.7m less $5m of LCE). The difference arises from the different methods used to derive the revenue requirements, and in particular the $118m used in the AoB allocation excludes any allowances for wash-ups and prior under recovery etc. The result is that there is a difference in the HVDC modelled revenue between the Status Quo and the AoB scenarios, but this is within the uncertainty of the indicative charges.

Loss and constraint excess

The loss and constraint excess (LCE) is not explicitly modelled in the TPM charges spreadsheet. Consistent with the earlier TPM modelling (i.e. 2015), the LCE has been netted off the revenue requirement prior to the cost allocation amongst parties. This is the same approach as used for the connection charges, and is shown in the table below (from the ‘revenue recovery’ tab on the results spreadsheet). The LCE and connection charges are treated consistently between the Status Quo and the AoB scenarios; in each case these amounts are netted off prior to the cost allocation amongst parties – only $796m (of the total 970.6m RCP2 2019/20 revenue) is allocated. In terms of the split of LCE between HVAC and HVDC, $45m is assumed to be related to HVAC and $5m to HVDC.

	Area-of-benefit	Residual charge	HVDC	RCPD	Connection	LCE	Total ($m)
Status quo (May 2016 update)			140	656	125	50	**970.6**

Proposal (May 2016)	296	500			125	50	**970.6**

Two different ‘Area of Benefit’ methods used in the allocation
There are two different ‘Area of Benefit’ methods used in the allocation. There are 11 transmission investments modelled in the Area of Benefit (AoB) charge. The largest 6 investments use the vSPD method to determine the net beneficiaries of these individual investments, and then allocate the charges in proportion to net benefit. The smaller 5 investments use a simpler regional based allocation.

The latter allocation can be thought of as more of an engineering determination of the main beneficiaries of an investment. In this method, a region (or group of regions or customers) may be allocated a share of the investment. The costs are then allocated within the region by gross AMD (MW) between offtake customers, and/or GWh/year for injection customers.

15. EnerNOC New Zealand Limited

Authority response

Thank you for your input. As you rightly point out, gross anytime maximum demand is intended to include “(a) the quantity of electricity generated by generation connected to the customer's network; and (b) the volume of demand-side management and demand response on the customer's network.” (Clause 26 of the draft TPM guidelines).

The residual charge is not intended to provide a price signal and is intended to be difficult to avoid. However, you raise an interesting point. The Authority would welcome it if you include a description of this issue in a submission on the TPM second issues paper. Note submissions are due on 26 July 2016.

Questions

This is just to follow up on our query regarding gross AMD calculation to clarify the authority’s current thinking. The workshop presentation lists the proposed calculation as:

gross AMD = the customer’s AMD plus distributed generation and demand-side response

In the Auckland workshop, it was asked if the demand-side response component included interruptible load. This was confirmed, perhaps in error.

Unlike demand response which the calculation is intending to capture, interruptible load is captured at the meter and will be factored into the customers AMD component by default. Counting this quantity twice is unnecessary.

We’ll include a point on this in any submission, just trying to clarify the initial thinking.

16. BusinessNZ

Authority response

We didn't do a quantitative CBA of the alternatives considered in chapter 9 but provide a qualitative assessment of those alternatives in chapter 9, and an assessment of those alternatives against the statutory objective in Table 6 in chapter 10.

Question

By the by, in chapter 9 the EA has considered a range of alternatives to the current set of proposals. Did the EA do a CBA of each of these? It'd be interesting to see what they came out to in NPV terms against the NPV of the current set of proposals.

Authority response

I don't think we have *exactly* what you are after but here are a couple of options that you could perhaps adapt. The first is Table 1 from the Executive Summary of the second issues paper and the second is the overview of the main components of the proposal, which we presented at the TPM workshops. Hopefully this is what you are after but let me know if not.

Alistair

Question

I'm still grinding my way through the paper, and I have to admit I'm struggling to bring all of the various bits of the preferred options together in my head especially the asset valuation preferred options. Do you guys have a simplified table that lists the three options (connection, AoB and Residual), the sub options (like standard and simplified for the AoB), the preferred asset valuation method, the charge type (lump sum etc) and basis of charge (gross AMD etc).

17. Pioneer

Authority response

Thank you for your letter seeking clarification from the Authority on a number of aspects of the independent cost benefit analysis (CBA) of the TPM proposal undertaken by Oakley Greenwood (OGW).

Our responses to your specific questions are set out below.

As a general comment, the purpose of the CBA is to provide the Authority with an estimate of the costs and benefits of the proposal, to assist the Authority in its decision-making process.

As you note, the Authority's Code Amendment Principles require it to use quantitative cost-benefit analysis. However the Code Amendment Principles also recognise that quantitative analysis may not always be possible.

As set out in the second issues paper, the Authority considers that, in addition to the benefits quantified in the OGW CBA, there are also some very substantial net benefits that have not been quantified. However, the Authority would value submissions on the assumptions, so as to facilitate a robust CBA.

Question 1: *The CBA considers the incremental costs and benefits of both the area of benefit (AoB) charge and deeper connection charge. The CBA appears to differentiate between the two options based only on percentage inputs for Capital Programme Impact and Avoided Disputation Costs. Can the Authority clarify if there is any relationship between the CBA and the actual charges being proposed in its Proposal?*

The Authority is of the view that OGW adopts a reasonable approach to modelling the costs and benefits of the area-of-benefit based proposal and the deeper connection option. As you note, the OGW quantified only a limited number of differences between the two approaches. The major differences between the two approaches are set out in the qualitative analysis contained on pages 74 and 75 of the OGW report.

Question 2: *The Proposal provides for Transpower to impose an additional charge to recover its residual costs (the Residual Charge). Can the Authority explain how the relative allocation of charges, both initially and over the term, between the AoB and Residual Charges has been addressed in the CBA?*

The OGW CBA does not take account of the relative allocation between the AoB and the residual charge. The Authority's view is that this approach is reasonable because the modelled benefits arise from, amongst other things, the change in marginal price signal that investors face with respect to new investments (ie, the application of the AoB charge to future, demand driven investments), and the way in which the cost of historical investments is recovered. The Authority's proposal is that the latter would be achieved by a charge that is based on a measure of physical capacity. OGW assumes that this will not distort marginal consumption or investment behaviour, so that its magnitude is of no particular relevance, except to the extent that it would lead to prices that are above a customer's stand-alone cost of supply. The latter is captured separately as part of the analysis of the enhanced prudent discount policy (PDP).

Question 3. *OGW have stated on a number of occasions that a key issue affecting the benefits of the Proposal is the effectiveness of the price signal, and that there remains some uncertainty in this regard. This is best exemplified in OGW's commentary on marginal price signals where OGW concludes that "If any of these factors do not hold true, the benefits described and quantified in this CBA will exceed those that will occur in practice". Can the Authority explain why the CBA does not include any allowance relating to the effectiveness of the Proposal, either as an input assumption or a key sensitivity?*

The CBA states that "…both of the proposed transmission pricing options appear to meet [the] threshold tests…" necessary to ensure that the price signal is not diluted (page 23 of OGW report). In addition, the Authority explicitly commented on this point in the second issues paper. It stated that while the price signals sent by the Authority's proposal are unlikely to be perfectly accurate, the Authority is confident that the price signals sent by the Authority's proposal will be sufficiently service-based and cost-reflective, and provided with sufficient lead time, to engender the type of response that OGW model.

Question 4. *OGW have assumed that there are no low cost alternatives to transmission investment (eg, hydro, geothermal, solar) on the assumption that the most economic sites have already been identified and developed. Can the Authority please provide the evidence used to support of this assumption?*

The assumption that there are no low-cost alternatives to transmission is intended to simplify the analysis. OGW assesses that this modelling assumption is conservative; that is, making the assumption will not lead to an overstatement of the benefits of the proposal. Changing this assumption would make little, if any difference to the results, because if there were additional low cost (ie, lower than the cost of the alternative investment, being a transmission investment) alternatives available in the future, these solutions would be dispatched under both the existing RCPD charge and the proposed AoB charge.

Question 5. *OGW have stated a number of times that there is a degree of inherent uncertainty in its analysis of the benefit from more efficient co-investment in generation and transmission services and therefor the lower bound economic benefit for this component of the CBA should be* *zero. Can the Authority please explain why this realistic lower bound was not presented as part of the results or the sensitivity analysis?*

The lower bound was described in the CBA as a “worst case scenario”, not a "realistic" lower bound as you suggest. The CBA identifies that even under the most extreme and unrealistic assumptions, the net benefits modelled will not turn negative, and therefore the overall benefit of the proposal would remain positive. OGW does not see the lower bound as realistic, as shown in its quantitative modelling.

Question 6. *OGW have concluded that existing distributed generation provides a positive economic benefit and would do so in the future even with the continued use of the current RCPD charge6. This is in direct contrast to the conclusions reached by Concept Consulting in their CBA of the Distributed Generation Pricing Principles. Can the Authority explain how they have reached these conflicting conclusions relating to the efficiency of existing distributed generation?*

The two CBAs do not reach different conclusion about the benefit of exiting DG. In particular, as indicated in paragraph D.8 of the Authority’s paper *Review of Distributed Generation Pricing Principles: Consultation Paper*, Concept assumes that most DG will continue to operate. As stated in the OGW report, OGW make the modelling assumption that all existing DG stops operating, but this is a conservative assumption because some DG will continue to operate. (Footnote 54 of the OGW report states that “The estimated gross benefit from more efficient pricing of historical investment comes entirely from transmission being more efficient than other new investments such as diesel generation. However, it should be noted that the modelling of this benefit (from more efficient pricing) in isolation implicitly assumes that existing distributed generators might cease operations straightaway in response to the effective removal of the RCPD price signal. This is a conservative assumption, as this: a) actually leads to a reduction in the benefit of removing the RCPD charge (because the cost of existing distributed generation is assumed to be less than the LRMC), and b) does not reflect the fact that many of these existing plants will continue to operate in response to the new cost-reflective transmission charge (eg, the AoB charge). To be conservative, we have not explicitly modelled this in the “Future investment in services or equipment that may otherwise be substitutes for transmission services” section – but this the likely outcome”).

Question 7. *OGW have assumed two separate benefits associated with a change in the cost of the generation schedules, being the more efficient co-investment benefit and the removal of the HVDC charge, as a result of the Proposal. Can the Authority explain how a single change in price signal (the Proposal) would influence independent benefits from different changes to the same generation schedule? ie, these benefits must be mutually exclusive and not additive.*

As is summarised in table 1 of the OGW report, OGW has modelled separately a number of benefits that would arise from the proposal to replace the current TPM with the Authority's proposal. We understand from OGW that it has done this so that readers can gain an understanding of what is contributing to the overall net benefits. Even though these benefits are modelled separately, they would all arise as a consequence of implementation of the Authority's proposal and are therefore additive.

Question 8. *OGW have assumed in their analysis that there will be no material upfront or ongoing costs for Load Customers or Generation, and significant avoided dispute related costs. Both of these assumptions appear to be arbitrary given the Proposal promotes a significant increase in bi-lateral agreements between Transpower and Industry participants which will inherently have a corresponding impact on transaction costs and durability. Can the Authority please provide some evidence that supports their assumptions for upfront and ongoing costs?*

As noted in paragraph 8.20 of the second issues paper, the Authority agrees that the implementation costs are underestimated. However, it also notes that the sensitivity analysis shows that any reasonable estimate of the implementation costs would not significantly alter the net benefit estimated by the CBA.

Question 9: *The Authority provided OGW with the capex data set as a basis for modelling the LRMCs of providing transmission services. Can the Authority please confirm the following:*

a *The source of the capex data set information that includes major capex, base capex and opex on an annualised basis, and why this expenditure is assumed to be static over the modelling period?*

b. The source of the split in the capex data set components between Load and Generation, specifically the percentage input assumptions (60:40) that have been used for allocating major capex between Load and Generation?

c. The source of the split in the capex data set components between regions, specifically the percentage input assumptions that have been used for allocating major capex between Load and Generation regions?

(a) Given the uncertainty around major capex over the 20 to 30-year analysis timeframe, assumptions were necessary. For the final load split, a table was compiled using historical and forecast major capex information, as discussed below. The assessed benefits of investments and location of investments required some judgement. Transpower's updated "RT06" file was used to source information. This spreadsheet is published by Transpower and is available from Transpower's website. Note the average major capex in the RT06 file between 2004 and 2025 was $154m pa whereas the major capex scenarios were based on the more conservative assumptions of $50m and $100m pa respectively.

The allocation to regions for generation was based on GWh produced in each region. 2014 generation data was used. A simplified allocation method was applied here because of the difficulty of allocating the benefits of investments to specific generators.

The RT06 file was the source for base capex and operating expenses data. For major capex, base capex and opex, expenditure was assumed to be static over the period so to be conservative.

(b) The 60:40 split between load and generation is an approximation. It reflects a high level understanding that economic investments benefit generation and load while reliability investments are of a greater benefit to load.

(c) The split between regions for load is based on historical data as outlined in the table below. The split between regions for generation is based on GWh produced in each region in the 2014 calendar year. The 2014 year was seen to be an appropriate year as there were both northward and southward flows across the HVDC in that year and the flows were seen to be broadly representative of a "typical" year.

Year	UNI	LNI	USI	LSI	Total	Source
2004	2062536.938	1,719,583	1,688,558	81,113	5,551,791	Actual based on where investment is located
2005	154769.839	78,852,633	7,310,984	65,501,658	151,820,044	Actual based on where investment is located
2006	6137163.249	5,788,269	5,782,413	1,975,821	19,683,666	Actual based on where investment is located
2007	105763.014	4,536,760	737,799	364,244	5,744,566	Actual based on where investment is located
2008	3477821.515	2,030,953	6,454,077	669,293	12,632,144	Actual based on where investment is located
2009	5825516.683	479,483	213,653	2,970,147	9,488,799	Actual based on where investment is located
2010	188,200,191	80,022,532	44,731,776	23,862,771	336,817,270	Actual based on assessed benefits
2011	319,388,502	110,140,416	35,233,930	31,778,072	496,540,920	Actual based on assessed benefits
2012	383,958,039	136,269,870	59,023,865	44,455,558	623,707,333	Actual based on assessed benefits
2013	242,827,953	85,970,234	29,131,337	33,680,394	391,609,919	Actual based on assessed benefits
2014	121,071,738	55,351,271	25,445,769	31,400,063	233,268,841	Actual based on assessed benefits
2015	37,174,756	23,775,571	11,644,091	19,735,142	92,329,560	Actual based on assessed benefits
2016	33,526,077	24,905,962	10,627,750	20,627,750	89,687,539	Forecast based on assessed benefits
2017	38,059,947	28,491,974	9,109,550	23,589,550	99,251,021	Forecast based on assessed benefits
2018	44,362,395	46,848,238	5,561,250	15,503,250	112,275,132	Forecast based on assessed benefits
2019	34,649,116	51,775,282	975,000	975,000	88,374,398	Forecast based on assessed benefits
2020	14,738,164	38,336,235	433,000	433,000	53,940,399	Forecast based on assessed benefits
2021	24,450,350	27,619,255	24,673,582	8,525,456	85,268,642	Forecast based on assessed benefits
2022	35,487,910	27,584,209	25,557,647	6,370,234	95,000,000	Forecast based on assessed benefits
2023	47,027,855	41,044,264	25,557,647	6,370,234	120,000,000	Forecast based on assessed benefits
2024	50,297,293	35,338,403	10,376,861	13,987,443	110,000,000	Forecast based on assessed benefits
2025	71,288,240	55,132,299	16,691,798	18,916,663	162,029,000	Forecast based on assessed benefits
Average capex	77,466,913	43,727,895	16,225,561	16,898,766	154,319,136	
	50%	28%	11%	11%	100%	
Allocation for $100m annual major capex	50,199,162	28,336,016	10,514,290	10,950,532	100,000,000	
Allocation for $50m annual major capex	25,099,581	14,168,008	5,257,145	5,475,266	50,000,000	

A number of sensitivity analyses were undertaken of the allocation of major capex between regions for load and generation. This was not reported in the OGW CBA. Sensitivity analysis was also undertaken in relation to the change in cost of a given quantity of capex. None of the sensitivity analyses had results that were inconsistent with the broad conclusions of the OGW CBA.

Question 10. *OGW have only used major capex in its calculation of the LRMC in all scenarios, on the assumption that this is the category of capex that would primarily be driven by growth in peak demand. However, the Proposal ultimately allocates all future capex under an AoB which implies that in reality these charges will be much higher than modelled. Can the Authority comment on the relationship between the use of a muted LRMC for modelling purposes and the actual charges under the Proposal, and the corresponding impact on the benefits being reported?*

Base capex is largely replacement and refurbishment capex. Replacement and refurbishment capex has no impact on the LRMC, hence its exclusion. OGW has assumed that to a large extent the timing and capacity of replacement capex is determined by technical considerations and so not affected by sending a cost reflective price signal, so including replacement capex in the area-of-benefit charge would alter neither the optimisation nor the benefits as they are assessed by OGW. However, as the Authority makes clear in the second issues paper, it is of the view that sending a service-based and cost-reflective price signal for replacement capex is also like to lead to more efficient investment, and so the Authority's view is that from this perspective, the benefits will be larger than OGW assesses.

Question 11. *OGW have adjusted all raw LRMC calculations downward by 30% to account for the fact that the analysis was undertaken over 19 year due to data availability. Can the Authority confirm which input data assumption or set was limited to 19 years?*

The analysis was limited to 20 to 30 years. The capital expenditure program provided by the Authority was also for 20 years. In reality the assets will serve customers for far more than 19 or 20 years. The OGW CBA has made adjustments to take account of this difference.

Question 12. *OGW have used the Interactive Electricity Cost Model – 2015 from the Ministry of Business, Innovation and Employment as the basis for determining the generation project schedules. Of the seven projects included in the project schedule and used for determining the benefit, approximately 1,000MW or 77% of those projects have been abandoned. Can the Authority comment on the robustness of the CBA in the context that some of the key input data is no longer relevant?*

OGW has relied on the information that it was aware of and that was available in the public domain at the time of developing the CBA. The Authority informed OGW of a number of changes that it was aware of in relation to the projects that were included in the project schedule, which OGW subsequently used to make adjustments for in its modelling. The Authority is satisfied that the OGW CBA provides a reasonable assessment of the costs and benefits it has quantified. In addition, as noted above, the Authority is of the view that the unquantified benefits are likely to be substantial.

Question 13. *Can the Authority clarify why the more efficient co-investment in generation and transmission services benefit has been calculated based on overall costs (ie, upfront capital costs, fixed operating costs per MW, variable operating costs per MWh, and transmission costs per MWh) and not just the transmission costs? ie, presumably the balance of these costs could only have an influence of market prices, the effect of which has been excluded elsewhere by the Authority and OGW.*

OGW has made the assumption that when faced with a service-based and cost-reflective price signal for new transmission, potential investors in generation will take account of both the total cost of generation and the additional cost to them of transmission. That is, if nodal prices were the same everywhere, it would maximise its return on investment by minimising the total cost of investment in and operation of generation profits plus the cost of transmission charges they face. This means that from an economic perspective, a potential investor might trade off higher generation costs, for lower transmission costs, if this led to the lowest overall costs. This is why both sets of costs (ie, transmission and generation) must be included in the analysis – otherwise, this trade off (higher generation costs stemming from a generator seeking lower transmission costs) would be incorrectly omitted from the analysis. The Authority agrees that this assumption is appropriate.

Question 14. *OGW have adjusted the raw Load LRMC calculations downward by 40% to reflect advice from the Authority that not all transmission investment is caused by standard percentage growth in demand in regions leading to capacity being constrained. This adjustment is in addition to the related assumption about the proportion of annual capex influenced by demand (question 10 above). Can the Authority confirm the basis for this assumption, specifically the 40% discount factor that has been applied?*

The basis is documented in the Appendix A, page 81 of the OGW report. ("The load related LRMCs have also been adjusted downward to reflect advice from the Authority that some investments are based on changing patterns of demand caused by exit and entry of large plant; it is not all caused by standard percentage growth in demand in regions leading to capacity becoming constrained. The LRMC's revealed in other jurisdictions have also been considered when making this assessment").

Question 15. *OGW have included historical RCPD data that differs significantly (regionally and in total) from available Transpower data and forecast information. Can the Authority confirm the source of the RCPD data that has been used in the CBA?*

The regional coincident peak demand (RCPD) numbers referred to actually represent regional (winter) peak demand numbers provided by the Authority to OGW on 7 December 2015. (This data was sourced from the file Transpower National-Regional Peak Demand Forecasts Feb2015.xlsx).The use of these numbers impacts on the calculation of three impacts within the CBA:

- Benefits of removing the RCPD charge
- Demand response (as a transmission substitute) and
- Reduced demand (through the elasticity impact).

In terms of the RCPD benefit, this is based on a gradual take-up of distributed generation (DG) to a cap of 5% of demand over 20 years. Take up only occurs where the cost of DG is less than the current RCPD charge (around $2300/MWh). This is then converted to a forecast level of electricity (based on regional peak demand information provided by the Authority) that would be provided through DG. The benefit is then that the investment in DG delays the need to augment the transmission network. OGW assume that peak demand is the underlying driver of the need to make investments to augment the transmission network, therefore they have linked the take up of DG (where economic) to peak demand figures, not the RCPD figures. This is reasonable.

Similarly, the incentive for demand response (ie, as a transmission substitute) is based on cost of demand response (DR), relative to the cost of augmenting the transmission network. Again, given peak demand is assumed to be the underlying driver of the transmission augmentation, OGW have linked the take up of DR to the forecast of peak demand provided by the Authority.

OGW agrees that the reduced demand (or elasticity impact) should have been explicitly based on the RCPD numbers. However, it considers that the impact of changing these numbers is immaterial (eg, less than $200k impact to overall NPV).

Question 16. *OGW have modelled two benefits relating to the future investment in services or equipment that may otherwise be substitutes for transmission services, namely the Demand Response Benefit and the Deferral Benefit. We understand the principle of deriving benefits from substitutes for transmission services; however it is not clear how the new price signals from the Proposal will provide these benefits over and above the status quo? Particularly as OGW separately concludes that the current TPM price signals incentivise substitutes for transmission services. Can the Authority clarify how a benefit can be derived from contrasting treatment of the same substitutes for transmission services? ie, these benefits must be mutually exclusive and not additive.*

The reason for the differentiation is the different price signals provided by the status quo and the Authority's proposal if it is implemented. As modelled by OGW the Authority's proposal removes the incentive for inefficient transmission – that is distributed generation and demand response that does not efficiently substitute for transmission. In addition, OGW models the Authority's proposal as incentivising distributed generation and demand response that does efficiently substitute for transmission. In other words, the distributed generation and demand response in the two circumstances refer to different investments. Since OGW models both benefits as arising from the Authority's proposal, the benefits are additive.

Question 17. *The OGW analysis of the RCPD Charge Benefit assumes current ACOT revenue of $62,000,000 per annum. However, ACOT revenue for the more recently completed 2015 pricing year was $52,000,000, a figure which the Authority had access to at the time of publication as it has been included in the Concept Consulting analysis of the Proposal8. Can the Authority explain why an outdated ACOT revenue figure was used as the basis for the CBA as opposed to the most recent figure or a historic average?*

Avoided cost of transmission (ACOT) payment information was taken from Commerce Commission disclosures for the year ended 2014. The Authority notes that ACOT payments have grown significantly, from $22m in 2008 to $62m in 2014– an increase of 177% over 7 years. The modelling for the TPM second issues paper is intended to reflect the 2019 calendar year. Given the growth rate of ACOT payments, the use of 2014 data is conservative.

Question 18. *The OGW analysis of the RCPD Charge Benefit compares the economic cost of existing distributed generation, new distributed generation (diesel only) and new demand response programmes and offsets these costs against an estimate of the benefits of those investments. Can the Authority explain why this analysis excludes existing demand response programmes (c. 1,000MW) that respond to the current RCPD price signal?*

OGW did not take into account the impact of existing demand response programmes on the CBA. OGW's view is that this is a conservative assumption. This is because if the costs of these existing programmes are below the estimated cost of transmission, then these would continue to operate in response to the more cost-reflective AoB charge, hence there would be no net change in the CBA (ie,, they would run, whether or not it was in response to the RCPD charge, or the more cost-reflective AoB charge). However, if they were in fact inefficient programs (ie,, their costs were higher than the transmission alternative), then their inclusion would result in the benefits of introducing the AoB option being larger than those that have been modelled (because the AoB charge would lead to the cessation of demand responses programmes that are in fact, inefficient).

We trust this answers your questions. We would welcome submissions on any issues that you would like to raise.

18. Pioneer 2

Authority responses in red.

If I may, there is one basic clarification I would like to your response to question 14 regarding the 40% discount factor that has been applied to the Load LRMCs. Your response references Appendix A, page 81 of the OGW report which is also referenced in the original question. However, the question itself was more specific to the 40% figure which has been used. Has the value of 40% been based on any empirical evidence or was this figure established by OGW at their discretion? If the former, can you please provide a reference? If the latter, can you please provide an explanation of how they arrived at 40%, as opposed to 30%, or 20% etc.?

Many thanks in advance.

OGW have advised that the discount was derived, having regard to the long run marginal cost (LRMC) outcomes in other jurisdictions. The 40% itself is not based on "empirical evidence", but the results derived from adopting the 40% is based on empirical evidence (i.e., it generates LRMC results that are in the range reported in other markets, namely Australia). See footnote 33 of the cost benefit analysis document and the associated text, which references an Australian Energy Market Operator (AEMO) document that has Transmission Use of System (TUoS) locational prices (which, as the document states, are based on the LRMC of supply) for one year. Note also that on the AEMO website, there are prices for a number of years, all of which were considered.

OGW also considered the LRMC's reported by various distribution business in Australia, particularly for their sub transmission network (which has the voltage most likely related to transmission. Almost all of these are between $10/kVA ($10,000/mVA) to $32,000/mVA. Note, the LRMCs will have been calculated by different parties because there are multiple businesses, yet they come out with fairly consistent numbers across the board. So again, this informed the range, which informed the 40%.

19. Meridian

<u>Authority responses in red</u>

I have a couple of queries on the treatment of embedded generation under the AoB charge. Appreciate any guidance you can give on the questions below.

1. Is it correct that under the EA's proposal it is not intended that the AoB charge be levied on embedded generation? I haven't found much discussion on this issue in the Second Issues Paper. I note that the TPM Options paper stated: "Embedded generation is potentially subject to the [AoB] charge if it is part of a scheme over 10 MW". Or will this just be a detail for Transpower to consider?

The area-of-benefit (AoB) charge as described in the draft TPM guidelines applies to designated transmission customers (DTC), which is defined in the Code as meaning "participants who are required to enter into transmission agreements with Transpower under subpart 2 of Part 12".

Under the Authority's proposal it would be for Transpower to determine whether it was consistent with the Code to make distributed generation (DG) subject to the AoB charge. Note that if generation benefits from transmission investments then it is likely that the benefits would not just be confined to grid-connected generation, eg, a transmission investment that removes a constraint would result in higher prices and increased dispatch for all generation benefiting from the investment, and not just grid connected generation. However, there would be materiality considerations, eg, the practicality of charging very small DG. Transpower would need to consider this in their development of the TPM if the Authority's proposal is confirmed.

The Authority welcomes you to address this matter in your submission on the TPM second issues paper due on 26th July 2016.

2. At our one-on-one meeting you indicated (if I interpreted correctly) it was likely that an AoB area could only generate net benefits for load <u>or</u> for generation but not both. Is it possible than an asset could deliver net benefits to both load and generation in a single area e.g. if non-price benefits (such as reliability) were sufficiently large?

In the case of economic investments, if both generation and load benefit from an investment it is unlikely they will be in the same area as only generation upstream of the constraint would be relieved through the investment and load downstream is likely to receive net benefits from the investment. Both generation and load in an area could both benefit from a reliability investment, with the benefit to generation being the ability to be dispatched more often than in the absence of the investment. However, the generation would need to receive net benefits in order to be charged.

The Authority's proposal does not rule out charging both load and generation in an area, and we would welcome any submissions on whether the guidelines need to specifically address this possibility, and if so how.
The Authority welcomes you to address this matter in your submission on the TPM second issues paper due on 26th July 2016.

20. Trustpower

Responses in red

I have a handful of questions on a couple of parameters in the OGW CBA (*General Inputs* sheet) I was hoping you could answer for me please – or request OGW to answer.

My questions are as follows:

1. **Cell H50: 'Cost of Diesel Generation ($/MWh) - based on 100 hours' = $1,125/MWh.**

   - H50 is a hard-coded number. Please could OGW provide the spreadsheet in which the calculations were made to produce this LRMC? We can do a reasonable back-calculation but would like to be sure.

Oakley Greenwood's (OGW) assumption has been that the units installed would be of a small scale (e.g., 1-2MW), self-contained (containerised) and standardised units – noting that units of this size are more likely to be able to use existing connection assets to inject back into the distribution network (i.e., they can possibly be co-located with an existing load). Such units also have fairly simplified injection processes with in-built standard features (e.g., 'loss of mains' protection relay and grid synchronisation) and self-contained 8hr fuel tanks with multiple injection points into a distribution grid. From a purely commercial perspective, such units also have the added benefit of being more flexible (in terms of their location), yet they still have reasonably long lifespans (e.g., 15 – 20 years). In short, they are likely to be a reasonably suitable technical response to the price signals being analysed.

The figures referred to in the question are for more permanent, larger scale diesel generation units, that would require different installation and integrity requirements (e.g., connection and network augmentation, additional fuel storage). Notwithstanding this, from OGW's experience, an installed cost of around $2000/kW is significantly above the likely actually costs for a large grid based permanent diesel power station. In Australia, based on OGW's experience developing remote area permanent diesel power stations, these type of power stations can be constructed in a greenfield setting for around $AU1000-$AU1200/kW (the range has been $800-$1200). The current exchange rate is approx. $1AU = $1.06NZ, so this is very similar in NZD terms. Furthermore, OGW traced the source of the pricing referred to from the Parsons Brinckerhoff (PB) report (2009) Thermal Power Station Advice - Reciprocating Engines Study, which was sourced from the World Alliance for Decentralised Energy (WADE) site http://www.localpower.org/deb_tech_re.html, which provided a broad range of $US900 - $US1300 (2006). The data provided by PB has been adjusted for the exchange rate and inflation to arrive at the capital cost. No reference or outline of the assumptions of the capital has been provided by the WADE information (i.e., country, inclusions or exclusions). Furthermore, there is no identification of the pricing being for diesel or gas, standby, prime, or continuous rating. This is an important consideration as the rating of diesel set operating only

100 to 200 hrs per year is different to one that is operating in a continuous, permanent installation. For example, the Cummins KTA50 which is a workhorse has different ratings 1120kW Standby, 1006kW Prime, 804kW continuous which results in a wide variance in $/kW. In summary, costs in the vicinity of $2000/kw are likely to be excessive, even for permanent, larger scale, diesel generation units.

Finally, to reiterate, all of the prices in the above paragraph relate to permanent, larger scale diesel generation units – the $550/kW that OGW used in its modelling is based on their experience and understanding of the pricing of small scale, self-contained (containerised) and standardised units, that are only operating for a fairly short period of time. For the purposes of completeness, even if one were to assume that this was at the lower end of the reasonable range of prices for these types of products, and the top end of the range for these types of solutions was assumed to be say 50% - 70% more, this would still lead to costs per MWh that are below the effective RCPD price signal, thus the use of such an assumption would, in fact, increase the expected benefits of introducing the area-of-benefit charge.

Note, an extract of a broader model has been attached. Refer excel attachment titled "TPM_questions_and_responses_CBA_assumptions_and_diesel_costs_added_22July2016".

2. Cell H24: 'Cost of Installing Diesel Generation ($/kW)' = $550/kW

- In our experience, particularly in having built the only diesel DG of reasonable scale in NZ, the $550/kW number appears to be too low. Please could OGW provide a reference for this number?
- Is it in NZD, and applicable for a NZ-based investment?
- Does it include the costs of resource consents, fuel storage, LV:HV transformation, HV connection and protections, land costs, transportation, and ground works?
- Could they reconcile the difference between this number and the $1,200/kW used by the EA in the UTS decision for 26 March 2011 (see http://www.ea.govt.nz/dmsdocument/10191) and the c. $2000/kW assumed by MBIE for Recip_Diesel_generic_x units in its new generation cost modelling data (http://www.mbie.govt.nz/info-services/sectors-industries/energy/energy-data-modelling/modelling/electricity-demand-and-generation-scenarios/draft-edgs-2015/generation-cost-assumptions.xlsx) and Interactive Electricity Generation Cost Model?
- Why is the capex estimate for 2025 of $1,320/kW so much greater? Is this number used at any point in the analysis?
- All figures were converted to NZD, however OGW did not explicitly take into account whether it was "applicable for a NZ-based investment", primarily because these are fairly 'stock-standard' solutions, that are not dependent on geographically specific circumstances.
- Dot points 3 and 4. Please refer to the responses to question 1.
- Dot point 5. This was an error in the report. Note that it does not impact upon the modelling results.

21. Fonterra

Fonterra question (relayed orally)

Given a situation where four parties in an area will potentially seek a load augmentation, Transpower should have an incentive to build a transmission facility big enough to service all four parties when the first party requests the augmentation. However, the first party to use the investment would be required to pay the full cost of the new investment under the area-of-benefit (AoB) charge, either forever (if no other parties joined) or for a period of time (if other parties join at a late stage).

Fonterra questioned how the proposed TPM guidelines would deal with the above situation.

Authority response

Where the asset in question is a connection asset, it is important to note that connection services are contestable. Parties can contract with parties other than Transpower for the provision of connection services to ensure that the desired amount of connection capacity is provided. The current TPM provides for situations where multiple connection customers share connection assets at a single point of connection. Costs are shared according to each customer's contribution to anytime maximum demand (AMD) or, in the case of generation, anytime maximum injection (AMI). The Authority has not proposed changing this aspect of the current TPM.

While the Authority does not consider it likely that the asset in question would be used to provide interconnection services, the proposed TPM guidelines anticipate this situation.

Where the asset is included in an investment that would be "major capital expenditure",[7] Transpower may seek approval for the investment under the Capex IM. The Commerce Commission essentially takes on the role of the representative of Transpower's customers. To have an investment approved, Transpower would need to demonstrate that the investment satisfies the investment test in the Capex IM. For most investments, Transpower would need to show that the proposed investment provides a positive expected net electricity market benefit.[8] Where a party considers that a proposed investment is too costly, that party would be incentivised to engage with the Commerce Commission in the investment approval process and provide information that demonstrated that there are less costly proposals that would achieve the same (or greater) benefits.

As a potential alternative, the Authority notes that nothing in the Commerce Commission's capital expenditure input methodologies (Capex IMs) prevents Transpower from entering into a customer investment contract (CIC) or a new investment contract (NIC) to finance an asset used to provide interconnection services, ie, customers could seek to enter into bilateral or multilateral contracts with Transpower to provide the optimum level of capacity desired. Note that the costs of assets constructed under these contracts fall outside the TPM.

[7] As defined by the Commerce Commission's capital expenditure input methodology (Capex IM).

[8] If an investment is required to ensure that the core grid (described in schedule 12.1 of the Code) meets the deterministic limb of the grid reliability standards in schedule 12.2 of the Code, the investment test will be satisfied if the investment is the lowest expected net electricity market cost.

Paragraph 18 of the proposed TPM guidelines sets out conditions whereby a party can apply for an AoB asset to be optimised including that the optimised value would need to be less than 80% of the value applied for the purposes of calculating charges. However, paragraph 19(b) of the proposed guidelines requires that the TPM specify "a period of time … which must be sufficient to ensure that the prospect of optimisation has a negligible impact on customers' motivation to seek new investment." This timeframe is intended to incentivise the parties to optimally trade-off the cost of having too much grid capacity if demand doesn't eventuate versus the cost of having to add sub-optimal amounts of capacity if demand does eventuate.

In the situation where a single customer was paying for an asset used to provide interconnection services and new or other customers started benefiting from the asset, the incumbent customer could apply for a reopening of the benefit calculation through the 'material change of circumstances' provision in the proposed TPM guidelines. Note that the proposed TPM guidelines do not specify the method for identifying the beneficiaries of investments in the AoB charge. Transpower would specify the methodology. The guidelines also require the TPM to include a method and process for Transpower to decide when a material change in circumstances has occurred. Note that the Authority has responsibility for approving a TPM proposal developed by Transpower and parties will have the opportunity to submit on Transpower's TPM proposal.

The Authority invites Fonterra and others to canvass this in their submissions on TPM second issues paper, due 26 July 2016.

22. Top Energy

Authority responses in red

Area of Benefit

- It is expected that charges under the AOB are allocated on the basis of positive net benefits and, where this is not practicable, will be allocated on the basis of physical capacity. Could you please clarify that the method of calculating the net benefits is not yet finalised and the expectation is that this will be determined by Transpower when they document the actual TPM?
  The Authority confirms that under the Authority's proposed TPM guidelines, the method for calculating "expected" positive net benefits is to be determined by Transpower as part of developing a proposed TPM. Note that the Authority is responsible for approving Transpower's TPM proposal and that parties will have the opportunity to submit on the TPM proposal.
- Under clause 13 of the TPM Guidelines the expected benefits are to be assessed for the expected remaining life of the investment from the latter of 1 April 2019 or commissioning date. Could you please clarify if this will include the reduction of benefits as a result of distributed generation, already commissioned and new distributed generation that has been committed and will be commissioned during the life of the eligible assets.
  The proposed TPM guidelines require Transpower to develop the methodology for identifying and quantifying benefits as part of developing a proposed TPM. Accordingly, a definitive answer cannot be provided until the Authority has approved a new TPM. However, in the meantime, the Authority observes that:

  - The question as to whether the benefit calculation would be adjusted for distributed generation (ie, whether the presence of distributed generation behind an offtake node would reduce the load benefits at that node) would depend partly on whether the existence of the DG reduces the net benefit to load at that point.
  - If vSPD is used to calculate benefits, a lower offtake volume (on account of DG) would mean it would be less likely that there would be a constraint in the system if the prospective investment was taken out (ie, the vSPD counterfactual) and therefore there would be less benefit to having the asset in place.
  - Parties would also potentially benefit, in general, because a smaller investment may be required on account of the DG and therefore there would be less overall cost to recover.
  - However, since the guidelines require that Transpower apply "expected benefits", if a new DG was commissioned after the investment took place, that new DG would not reduce the cost of the investment and therefore in that instance the Authority would not expect the DG to reduce the benefits to load.

- There is also a question as to whether a transmission investment avoids or defers investment in costly generation and reduces use of expensive generation already in place. There are no savings in the capital costs of distributed generation that is already in place and for new distributed generation that is already committed, and so the benefits of a proposed transmission investment wouldn't include those potential savings. Also, in the case of geothermal DG, it is considered to be 'must run' generation. Accordingly, the transmission investment wouldn't save operational costs in relation to those sources of generation.

Residual Charge

- This charge is allocated based on the physical capacity, which is still to be determined by Transpower but is limited to either Gross AMD or Transformer or Lines Capacity. Can you please confirm our understanding is correct?
  That is the proposal. Although it should be noted that the Authority has not made its decision and will consider submissions.
- Does this also mean that regardless of actual load flows on the transmission grid, these charges will be calculated based on the assumption that the load customer is fully utilising the grid.
  Under the proposal, the load customers' actual use of the grid after 17 May 2016 will not affect the charge. The residual charge is designed to be difficult to avoid through changes in behaviour. This is considered to be the most efficient way to recover the residual.
- Can you also please confirm that if the connection is initially deemed to be a load customer then charges to the consumer will remain even if the power flows in the grid reverse and energy is exported.
  "Load customer" is a colloquial term for an "offtake customer", a defined term in the TPM. An offtake customer is a customer that controls assets into which electricity flows from the grid in any half hour during a capacity measurement period. Offtake customers are required to pay the current interconnection charge.

  The second issues paper expressed the view that, like the current interconnection charge, the new residual charge should apply to load customers. Based on the definition of "offtake customer" in the current TPM, this means that any customer that has offtake will be a load customer and would need to pay the residual charge, even if at times the customer also injects electricity into the grid.

  If the customer does not offtake from the grid at all in a capacity measurement period (for example, if they install co-generation such that they never needed to offtake from the grid), under the proposed guidelines the customer would remain a "load customer" for the purposes of the residual charge, because they were a load customer at the time that the physical capacity calculation was made.

In such a case, it may be that the “material change in circumstances” provision could be used after the period of time specified in the TPM (refer clause 21 of the draft TPM Guidelines in relation to the area-of-benefit charge and clause 27 of the draft TPM Guidelines in relation to the residual charge). If the Authority confirms its guidelines, Transpower would be required to determine (in its development of the TPM) a method and process for Transpower to decide when a material change in circumstances has occurred. The Authority is responsible for approving the TPM and parties would have the opportunity to submit on any TPM proposal.

We would also like clarification on how the optimisation of the Area of Benefit (AOB) charge and the Prudent Discount Policy (PDP) are intended to work:

Optimisation

- A process is to be defined to determine any optimised value under the guidelines. Not knowing what this process will be creates significant uncertainty. There are a few initial questions we have:
- Under clause 19(c) of the TPM Guidelines, it states that Transpower has the discretion to revise values if the demand for an asset changes by more than 20%. Is this 20% of the asset as a whole, or 20% of one parties demand on the asset? What is the definition of demand, assuming it is not the same as physical capacity?
  This would be 20% of the value of the asset as a whole. Note that the value would be replacement cost for eligible investments commissioned after the date of the guidelines[9] and depreciated historical cost for eligible investments commissioned before the date of the guidelines. Note that optimisation would be available for area-of-benefit assets only.
- Under clause 21 of the TPM Guidelines, it states that Transpower is to review the charge if there is a material change in circumstances, which is not yet defined. Is this a material change in the net benefits that a party receives as an individual or a material change in the net benefits the asset provides on a whole? Clarification on what a material change could be would also be helpful.
  The draft guidelines would require that Transpower determine this in its development of a TPM. Note, the Authority is responsible for approving any TPM Transpower develops and parties would have the opportunity to submit on any TPM proposal.

Prudent Discount Policy (PDP)

- The economic rationale for granting prudent discounts is that the discounts avoid large inefficiencies. They enable Transpower to reduce charges to customers when it is considered necessary to meet the market costs of an

[9] The Authority's current preferred option is to value eligible investments commissioned after the date of the guidelines at replacement cost, but the Authority is yet to take a firm view about adopting this approach.

alternative to transmission assets. As you aware, Top Energy does have an option through the expansion of Ngawha to meet all our energy needs locally. As the Ngawha expansion is economic then it will proceed anyway. Our interpretation is that the PDP would not apply as the inefficiency has not been avoided i.e. consumers supplied from local generation will continue to pay for transmission assets south of Northland. Can you please confirm our interpretation is correct?

The Authority understands that Top Energy has the option to use the Ngawha expansion to meet all of its energy needs. Top Energy's question states that the Ngawha expansion is "economic". If by "economic" Top Energy means that the expansion would be privately beneficial but not efficient from an electricity market point of view, then a prudent discount would be available (but only if Top Energy does not proceed with the Ngawha expansion). However, if by "economic" Top Energy means both privately beneficial and efficient from an electricity market point of view, then no prudent discount would be available.

- Our current interpretation is that with the EA's focus on preventing parties from avoiding transmission charges, that consumers of the Far North will not see any benefit of having generation at their doorstep, but will be required to pay for a transmission system that will not be used. For economic generation this appears to incentivise disconnection from the grid which seems counter to your stated objective.

  The guidelines refer to a prudent discount being available if it would be privately beneficial for a customer to "build generation". In that respect, paragraph 36 of the guidelines reflects the current test for a prudent discount in the TPM for investments that would bypass the grid (but which are not proposed new generation). Accordingly, Top Energy would not be eligible for a prudent discount if it proceeded with the Ngawha expansion.