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Review of TPM CBA Inputs

Prepared for Electricity Authority

Date

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1 Introduction

Concept Consulting has been engaged to review certain input assumptions (see later table) that the Electricity Authority proposes to use for the Transmission Pricing Methodology (TPM) Cost Benefit Assessment (CBA) model.

These inputs have been updated since the initial CBA undertaken by the Authority on the TPM Guidelines to reflect a changing outlook on demand growth and technology changes over the next thirty years.

Concept has not undertaken to review any of the operation of the CBA model, or other underlying assumptions.

2 Summary of findings

We have noted areas where Concept's views differ from those used by the Authority. These are detailed in later sections, but the key points of difference are:

- Future battery costs appear too low.
- The "steepness" of the renewable generation supply curve appears too high.
- The cost of swing should be included in gas prices.
- The sensitivity range for generation costs seems low.
- The assumption about the operation of the Tiwai smelter (or equivalent demand in lower South Island) should be reconsidered and its implications for retirement ofHuntly Rankine units.

The Authority already has a sensitivity testing process in place. We suggest that if the Authority is concerned about differences in Concept's view and the Authority's approach that the effect of these differences is first tested by extending sensitivity testing to include the input.

It has proven somewhat difficult to cleanly distinguish between *input* assumptions (within scope) and more general assumptions (outside of scope). Concept has limited our responses to assumptions that are clearly for input values, and has not provided comment on other assumptions that may pertain to model methodology or similar.

Finally, we note the government has announced an ambition of achieving 100% renewable electricity generation by 2030, and is considering whether to formalise this and adopt supporting measures including legislation. We suggest that the Authority may want to consider a 2030 100% renewable electricity scenario, with relevant inputs changed. Such a scenario would likely have altered assumptions for thermal retirement, gas prices and need for new renewable build in the lead up to 2030 (among other changes).

3 Review of inputs

Concept has been provided with two sources of inputs to review. The first is a table that is part of a PowerPoint presentation.[1] The second is a list of references[2] to the TPM CBA technical paper.[3] There is some overlap in the two sources.

3.1 Review of PowerPoint table inputs[4]

Input	Value used in update CBA	Concept comments
Wind generation capital costs (LRMC)		
Range for $ per MWh in 2020 ($2018)	$66.9/MWh - $97.3/MWh	We understand that this range is based on the wind generation stack update published by MBIE in 2020. The lower bound is similar to what we've seen recently in the market[5], which suggests that it is a reasonable estimate of the cost for the "next cab off the rank" project. However, we disagree with the "steepness" of the supply curve, or in other words, we don't believe that the generation stack update includes all possible new wind sites in the next 15 years and beyond. For example, Genesis' recently announced Kaiwaikawe wind farm does not appear in the wind generation stack update (nor its previous name of "Omamari"). Accordingly, we believe that the increase in costs as successive wind farms are built is likely to be lower than that presented in the generation stack, and accordingly, that used in the TPM CBA.
Range for $ per MWh in 2035 ($2018)	$61.8/MWh - $88.5/MWh	This implies an annual reduction of 0.5-0.6%. Our modelling assumes a higher rate of 1%/yr cost reduction to 2035, then 0.5% to 2050. However, there is a wide range of viewpoints on the learning rate for wind, depending on whether the forecaster assumes all of the "easy gains" have been achieved yet. For example, in their Te Mauri Hiko report, Transpower shows NREL results that imply

[1] Attached as Appendix A.

[2] Attached as Appendix B.

[3] "CBA approach, methods, and assumptions – TPM decision paper 2020". https://www.ea.govt.nz/assets/dms-assets/26/26849Technical-paper-CBA-approach-method-and-assumptions.pdf

[4] We note that input prices and costs are quoted in 2018 dollars. Concept has undertaken a high-level review and as such we consider the effect of inflation since 2018 to be negligible to our feedback.

[5] Concept Consulting recently undertook a review of the LCOE of recently constructed and committed projects for Phil Bishop at the Authority.

		significantly more aggressive annual cost reductions of about 2.2%. On the other hand, CSIRO, in their GenCost 2020-21, show results that imply annual reductions of 0.33% to 0.66% to 2040. We consider the cost reductions assumed in the TPM CBA to be reasonable. However, as for 2020, we consider that the "steepness" of the supply stack is overstated.
Average annual growth	-0.80%	We understand that this is the escalator that is applied to capital costs, which are a part of the calculation to determine the LCOE shown above. We have not directly reviewed this escalator, but instead review the LCOE projections for 2035 above.
Utility scale solar generation capital costs		
Range for $ per MWh in 2020 ($2018)	$87.2/MWh - $113.4/MWh	This appears to also be based on MBIE's solar generation stack update. Concept's view falls roughly in the middle of this band. Lodestone's recently announced wind farm investment project claims an LCOE of 68 $/MWh, which is significantly cheaper. While we view this as an interesting data point, we also note that given current electricity prices (and shape), the Lodestone investments would appear economic at a much higher LCOE. The difference between the upper and lower bounds is lower for solar than for wind. We agree with this, as utility solar is less site dependent that wind. Having said that, our previous comment about the "steepness" of the generation stack and not including all possible generation projects is repeated for solar. We recommend that the EA reviews the implementation of the solar supply curve with this in mind.
Range for $ per MWh in 2035 ($2018)	$59.8/MWh - $76.9/MWh	These costs in 2035 imply annual cost reduction of about 2.5%. We estimate a higher annual cost reduction of 3.5%/yr until 2035, which then drops to 0.5%. Again, there is a range of views on this, although less so than for wind. Most sources assume that the learning rate for solar remains steep. • Transpower shows NREL results that imply annual cost reductions of about 4.2% to 2035 • MBIE's solar generation stack update expects annual reductions of about 3.7% to 2035 • CSIRO expects annual reductions of between 2% and 3.75%. The EA's assumed cost reductions appear slightly lower than most viewpoints, but not unreasonable.

Average annual growth	-3.00%	We understand that this is the escalator that is applied to capital costs, which are a part of the calculation to determine the LCOE shown above. We have not directly reviewed this escalator, but instead review the LCOE projections for 2035 above.
Step changes in demand		
Tiwai departure	Close end 2024 - 5,322 GWh	This is a key assumption that we expect will have already been highly scrutinized and debated. Our view is that it's likely there will be some form of demand of a similar size to the Tiwai smelter until (at least) 2035, but we don't think that assuming it leaves is necessarily unreasonable given the prevailing uncertainty. However, we suggest that the effect of this assumption be investigated via scenario analysis. During discussions with the Electricity Authority, the issue of how the transition from Tiwai to some other source of demand arose. We expect that all parties involved would attempt to have this transition as seamless as possible, as a disruptive transition would result in energy spill and economic loss. As such, we think it's reasonable to assume that there would be no "downtime" when considering the replacement of the Tiwai smelter with an alternative Southland demand or some other solution.
Norske Skogg	Close 2021 -498 GWh	Agree
Marsden Refinery	?	This closure/repurpose has been announced and will result in a large reduction in electricity consumption. We don't have visibility on the exact current consumption as it is embedded behind the Bream Bay point of connection. We estimated current consumption of ~350 GWh/yr but the EA will have access to better data.
Gas prices, central scenario		
$/GJ in 2020 ($2018)	$6.35/GJ	In our view this is somewhat low. Average spot gas prices for the previous three years are about 11 $/GJ, reflecting the currently constrained nature of gas supply. While most users are insulated from short term price movements through long term contracts, sustained periods of high spot prices will inevitably flow through to contract prices. MBIE publishes a "wholesale" gas price series based on the price that major users pay. This has remained at about 6.7 $/GJ for 2017-2020, and increased to

		7.3 $/GJ for the first quarter 2021. We suggest that a value of 6.7 $/GJ may be more appropriate as a lower estimate. Our comments thus far have assumed that this is a *baseload* gas price. Such an assumption may be appropriate for some generators in 2020 that operate with a high capacity factor. For intermittent or peaking generation, a significant premium for flexible supply (or swing) would need to be added to the baseload price. Our modelling suggests that a gas supply that is only called upon 10% of the time would result in an effective gas price of more than double that for a baseload supply.
$/GJ in 2035 ($2018)	$6.66/GJ	Most of our previous comments for 2020 also apply to the gas price in 2035. While historical prices do not necessarily reflect future gas prices, it is Concept's view that it is unlikely that the long-term price of gas will decrease by 2035. Our comment about baseload versus swing gas is particularly relevant as we expect that thermal generation would operate at significantly lower capacity factors in 2035.
Average annual growth	0.30%	This escalation rate is very similar to Concept's view. We also don't anticipate a significant increase to the price for *baseload* gas to 2035.
Emissions prices		
$ per tonne 2020 ($2018)	$28.8/t	This is consistent with carbon prices seen in 2020. We note that the carbon price has increased further in 2021.
$ per tonne 2035 ($2018)	$154.3/t	This seems reasonable. The Climate Change Commission (CCC) estimates a required carbon price of 160.5 $/tCO2 in 2035, and we use this value as our default assumption. Note that this is the price needed to achieve their emissions target, rather than explicitly a forecast.
Average annual growth	11.80%	This isn't consistent with the prices in 2035 and 2020 and seems excessive if utilized beyond 2035. After a large rise to 2030, the CCC estimates a 3% growth per annum.
Exogenous demand growth, average % growth		
Total	2.00%	This is rate of growth lies between Transpower's base case of "accelerated electrification" and the higher "mobilize to decarbonize" sensitivity. We consider a 2% rate of demand growth to be on the high side, but not implausible.
Population growth	0.74%	

Income growth	0.14%	Concept's demand growth modelling is undertaken on a different basis to the TPM CBA's. We utilize three different demand types: electric vehicles (EVs), process heat and conforming demand, with roughly a 40%/40%/20% split respectively to 2035. Our EV and process heat sectors appear similar to "electrification", and combined we assume a 0.8% annual growth to 2035.
Electrification	1.13%	
Exogenous construction		
Junction road peaker	Commissioned	
Turitea wind, stage 1	119 MW, by 2022	
Turitea wind, stage 2	103 MW, by 2023	
Mt Cass wind	93 MW, by 2023	We understand this is not technically committed, but is still highly likely to proceed.
Tauhara geothermal	152 MW, by 2025	Contact intends to complete Tauhara stage 1 in mid 2023, suggesting that it should be included in the model from 2024.
Harapaki wind	176 MW, by 2025	
Total	643 MW, 2022-2025	
Kaiwaikawe wind farm	?	We suggest this be included in the model as 75 MW from 2024
Decommissioning		
Huntly gas/coal units (rankines)	-500 MW end 2024	We assume that this represents all modelled Rankine unit capacity. Currently there's 750 MW of Rankine units operating, but Genesis's stated intention is only to keep the third unit available until September 2021. We consider it appropriate to model the current Rankine unit capacity as 500 MW. We think that Rankine unit retiral will be closely linked to what happens to the Tiwai smelter (or other similar demand). If such a demand remains, we think it's unlikely that the Rankine units will exit in 2024. We note that the 643 MW of new generation listed above is not sufficient to replace the energy potential of two Rankine units (due to the lower capacity factor of wind). As such, we recommend that any exogenous retirement of the Huntly Rankine units should be tied to the Tiwai retirement assumption.

		For longer term planting decisions (i.e. 5+ years) we would expect these to be determined endogenously by the Authority's modelling. One exception to this is the proposed 100% renewable generation in 2030 scenario, as it is unlikely that the Rankine units would still be running in this scenario.
Huntly unit 6	No Change	We agree with this as we think it's likely that the majority of current peaker capacity will be retained until 2035. There will be a large requirement for peaking capacity, and this is most economically met by existing peaker plant.

3.2 Review of CBA assumptions technical paper

Input	**EA's assumption**	**Concept Comments**
Demand - draws on 2016 EDGS Mixed renewables, updated (p8-10).		We have reviewed national demand in section 3.1. Concept does not have a view on regional level demand but considers the population and income approach undertaken by the Authority to be reasonable.
Detailed demand by TOU and demand for peak dg / price elasticity modelling page 26 ff.	Multiple, assumptions. The key η_{ee} (or electricity demand elasticity) parameter = -0.022	Concept has not reviewed the demand elasticity theory in detail, nor the derivation of industry specific demand elasticities and alternative energy source elasticities. We have focussed our review on the η_{ee} parameter, as it is analogous to traditional "demand elasticity". Electricity demand elasticity is highly dependent on the time frame considered. The value used by the EA appears to be a long-term value since it is derived from annual energy data from 1990 to 2016. Concept's experience with demand elasticity is focussed on short term response to high price events, rather than long term incremental changes to demand based on minor price uplifts or decreases. For such response, we use a value of about -0.005, but we do not consider this to be directly comparable to the Authority's implementation. In lieu of hands-on expertise, Concept has undertaken a quick review of international literature.[6,7,8] The literature supports our assertion that elasticity varies dramatically depending on timeframe

[6] https://comcom.govt.nz/__data/assets/pdf_file/0024/62871/ENA-submission-on-proposed-DPPs-for-EDBs-2015-Sapere-Trends-in-Residential-Demand-15-August-2014.PDF

[7] Burke Abayasekara 2017, "The price elasticity of electricity demand in the United States: A three-dimensional analysis".

[8] Andruszkiewicz, Lorenc and Weychan 2019, "Demand Price Elasticity of Residential Electricity Consumers with Zonal Tariff Settlement Based on Their Load Profiles".

		considered. For long-term response, the literature suggests significantly higher values than those derived by the Authority. We recognize that values for New Zealand may differ somewhat (particularly for industry), but nevertheless the Authority's estimate is significantly lower than these values. We recommend that the Authority review these differences.
Generation offer prices for existing plant	Prices based on historical offers	In Concept's experience, basing offers on historical behaviour is difficult. The primary obstacle is that the quantity offered at a price low enough to lead to likely dispatch varies period-to-period depending on forecast demand. However, deriving offer prices from an average of historical offer prices results in an offer curve that does not. This means that prices from a dispatch based on the averaged offer curve will be more variable than observed. However, this problem may be mitigated or eliminated because the Authority is also dispatching averaged *demand*. It is not intuitively obvious to Concept exactly how this would affect resultant prices. We recommend the Authority compares modelled prices to historical prices, paying particular attention to their variability.
Generation investment	See section 3.1	See comments above on wind and solar development costs.
Operation and investment in batteries	1 hour storage	This seems unreasonably low. It is not uncommon for multiple RCPD periods to occur on the same day, and targeting these periods with only 1 hour of storage is unrealistic. Concept's modelling has indicated that the optimal storage capacity for batteries is about four hours.
	90% charging efficiency	Concept's battery modelling distinguishes between normal (or grid) batteries and electric vehicle charging. Concept assumes that grid battery efficiency is about 85%, while we assume that the majority of electric vehicle "charging/discharging" is low cost deferral of charging that results in demand shifting from peak to offpeak periods. Accordingly, we assume an efficiency of 95% for EV batteries. The Authority's value of 90% seems a reasonable amalgamation of these two distinct types of batteries.
	900 $/MW in 2020 dropping to ~375 $/MW in 2035	The Authority's estimate of ~900 $/kW in 2020 is consistent with Concept's view. However, the Authority's assumptions of ~375 $/kW in 2035 is significantly lower than Concept's estimate of ~500 $/kW for 2035.
Transmission costs	Estimate of total cost to recover	Concept considers the Authority's approach using Transpower's RCP forecasts to be reasonable

Approach to allocating LCE		Concept considers the implementation and distribution of LCE to be a modelling design feature rather than a model input. As such we have not reviewed how LCE is allocated, nor considered the effect it may have on results.
Sensitivity analysis approach and parameters		The general approach used for sensitivity analysis seems reasonable. Four types of inputs are varied: 1. Generation SRMC. The range of possibilities used here seems somewhat on the low side given the total number of sensitivities tested. Our earlier comments on carbon prices and the expected swing premium for gas price would lead to changes in peaker SRMC of a similar (or even greater) magnitude than that covered by the sensitivity analysis. Given that there are 12 different cost sensitivities tested, it would be prudent for these to span a wider range of outcomes 2. Generation LRMC. We have a similar comment here as for SRMC. A range of +/- 10% seems minor compared to the range of viewpoints on future costs of renewable plant. 3. Battery cost multipliers. Battery costs have a +30% sensitivity. This would increase the forecast cost for 2035 from ~375 to ~500 $/kW, which is similar to Concept's expectations for future costs. 4. Demand. In our opinion, the range of demand outcomes covers an excessively wide range of possibilities. Due to the exponential nature of how demand is modelled, and how the "growth shifter" is applied to both income and population effects, a seemingly small change to growth rates can lead to very large differences in total demand many years in the future. The lower growth sensitivity has no growth, while the higher growth sensitivity doubles demand over a 30 year period. In addition to *sensitivity* analysis, Concept recommend that the Authority includes *scenario* analysis in its modelling to test the effect of Tiwai leaving or staying.

Appendix A. PowerPoint presentation table of inputs

	Prior data/assumption	Updated
Wind generation capital costs (LRMC)		
Range for $ per MWh in 2020 ($2018)	$93.4/MWh - $121.6/MWh	$66.9/MWh - $97.3/MWh
Range for $ per MWh in 2035 ($2018)	$93.4/MWh - $121.6/MWh	$61.8/MWh - $88.5/MWh
Average annual growth	0.0%	-0.80%
Utility scale solar generation capital costs		
Range for $ per MWh in 2020 ($2018)	No data	$87.2/MWh - $113.4/MWh
Range for $ per MWh in 2035 ($2018)	No data	$59.8/MWh - $76.9/MWh
Average annual growth	No data	-3.00%
Step changes in demand		
Tiwai departure	Pot 4 off in 2022, -438 GWh	Close end 2024 -5,322 GWh
Norske Skogg	None	Close 2021 -498 GWh
Gas prices, central scenario		
$/GJ in 2020 ($2018)	$6.35/GJ	$6.35/GJ
$/GJ in 2035 ($2018)	$9.07/GJ	$6.66/GJ
Average annual growth	2.4%	0.3%
Emissions prices		
$ per tonne 2020 ($2018)	$35.6/t	$28.8/t
$ per tonne 2035 ($2018)	$69.7/t	$154.3/t
Average annual growth	3.8%	11.8%

Exogenous demand growth, average % growth		
Total	1.11%	2.00%
Population growth	1.00%	0.74%
Income growth	0.11%	0.14%
Electrification	0.00%	1.13%
Exogenous construction		
Junction road peaker	100 MW in 2022	Commissioned
Turitea wind, stage 1		119 MW, by 2022
Turitea wind, stage 2		103 MW, by 2023
Mt Cass wind		93 MW, by 2023
Tauhara geothermal		152 MW, by 2025
Harapaki wind		176 MW, by 2025
Total	100 MW in 2020	643 MW, 2022-2025
Decommissioning		
Huntly gas/coal units (rankines)	-500 MW end 2024	-500 MW end 2024
Huntly unit 6	-48 MW end 2027	

Appendix B. TPM guidelines CBA: overview of assumptions

See technical paper for assumptions in 2020 CBA

- Demand - draws on 2016 EDGS Mixed renewables, updated (p8-10). Note, updating this.
    - Population growth by backbone node. See para 2.259
    - Income growth by backbone node. (See para 2.260)
    - demand = fn(p, y)

- Detailed demand by TOU and demand for peak dg / price elasticity modelling page 26 ff.
    - Data 2010-2017 years as at August by network reporting region, load type.
    - Note not changing.
    - Price expectations and demand: see para 2.194

- Peak, shoulder, offpeak periods. (Cluster analysis: para 2.143). Note not changing.

- Generation prices: (para 2.163-2.173) [note changing detail input data and method]
    - Input data = EDGS (GEM) para 2.169
    - offer curves from observed (2014-2017) actual averages of existing plant
    - In 5 bands. derive expected average annual price for that time of use
    - Adjustment factors: esp shoulder/offpeak, calibrates for DG and diversity
    - producer surplus (revenue over short run cost, ex fixed costs) para 2.173

- Generation investment:
    - Para 2.203 re assumed gas peaker Junction Road, decommissioning Huntly
    - Para 2.199 investment model; not location-based. Just national capacity.

- Battery detail at paras 2.205-2.225
    - Treated as demand side investments
    - Optimal capacity: marginal present value earnings (rev-variable cost) = marginal pv capital costs (inc fixed op costs); earnings increase w peak demand charges
    - Profitability reduces as investment in batteries increases (as price differentials fall and opportunities to flatten load to avoid peak charges fall)

- Transmission costs
    - para 2.48 ff (TP's RCP3 revenue forecasts, wacc, depreciation, opex as a proportion of RAB and unallocated costs
    - table 5 p18 splits interconnection rev between load and generation 2022-2049
    - basis for allocation 50:50 economic and reliability p18-19
    - economic = allocated on shares of LCE, reliability = allocated 100:1 to load:generation (as voll=20,000/MWH and lost generation = 200/MWh), and among load on shares of AMD and generation on shares of AMI.
    - Cost of transmission brought forward: para 2.65-2.71.
    - LRAIC by transmission pricing region, Table 7 p22
    - Initial shares of BBC page 61-62

- Changes in LCE para 2.56… and para 2.74. [Note not intending to change]
    - Each model node has a mark-up (or discount) on national average price calculated by the model during periods of scarce (import) or abundant (export) local generation. Table 6 p20
    - LCE increases in proportion to demand growth. Model at para 2.174 ff. This change in LCE due to incremental peak demand growth under proposal = benefit of incremental transmission investment.

- Parameters for sensitivity analysis
    - Page 63 - 68