From the Electricity Networks Association

Submission on the Draft Electricity Demand and Generation Scenarios

Submission to the Ministry of Business, Innovation and Employment

15 May 2015

The Electricity Networks Association makes this submission along with the explicit support of its members, listed below.

Alpine Energy Ltd

Aurora Energy Ltd

Buller Electricity Ltd

Centralines Ltd

Counties Power Ltd

Eastland Network Ltd

Electra Ltd

EA Networks Ltd

Electricity Invercargill Ltd

Horizon Energy Distribution Ltd

Mainpower NZ Ltd

Marlborough Lines Ltd

Nelson Electricity Ltd

Network Tasman Ltd

Network Waitaki Ltd

Northpower Ltd

Orion New Zealand Ltd

OtagoNet Joint Venture

Powerco Ltd

Scanpower Ltd

The Lines Company Ltd

The Power Company Ltd

Top Energy Ltd

Unison Networks Ltd

Vector Ltd

Waipa Networks Ltd

WEL Networks Ltd

Wellington Electricity Lines Ltd

Westpower Ltd

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1. Introduction

1. The Electricity Networks Association (ENA) appreciates the opportunity to make a submission to the Ministry of Business, Innovation and Employment (MBIE) on the recently released Draft Electricity Demand and Generation Scenarios (EDGS).[1]

2. The ENA represents the 29 electricity network businesses (ENBs) in New Zealand.

3. Our submission covers the following issues:

(a) The EDGS do not meet their purpose in Transpower's Capex Input Methodology (IM) because the major capital expenditure investment test could not be completed without regional and prudent peak demand projections which are not included in the EDGS. The ENA recognises that this requires additional resource, and that it may be preferable to develop these forecasts at the time an investment is proposed. This would seem to require an amendment to Transpower's Capex IM.

(b) Further consultation is required on the demand-side projections because the model is not yet specified and as noted there are no regional or prudent peak projections.

(c) MBIE should test whether the assumptions and model results of the EDGS are reasonable and feasible.

(d) The demand-side of the scenarios are within too narrow a range and do not represent the possible outcome that demand declines (all scenarios assume continuous growth in demand).

(e) There are internal inconsistencies in demand within the scenarios for example there is no link made between the level of household demand overall and uptake of solar/EV technologies.

(f) More analysis of the components of demand (residential, industrial and commercial) and the likely profile of demand is needed as the ENA does not consider that the EDGS covers the range of likely outcomes particularly with respect to the prospect of declining demand for electricity.

(g) ENBs should be considered an important stakeholder in the assessment of new models as they can provide insights to the likely effects of diversity as load is aggregated through their networks to the grid.

4. We provide more detailed comment on these points in the body of our submission.

5. The ENA's contact person for this submission is:

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[1] Ministry of Business, Innovation and Employment, *Draft Electricity Demand and Generation Scenarios*, 2 April 2015.

2. Purpose of the EDGS

6. The ENA agrees with MBIE that the main purpose of the EDGS is as an input to Transpower's major capital expenditure (capex) investment test. This is specified in the Capex IM; clause D4(1)(b) defines a demand and generation scenario as a:

> *description of a hypothetical future situation relating to forecast electricity demand and generation published by the Ministry of Economic Development (or other agency which subsequently assumes the responsibility) for the purpose of the preparation or evaluation of major capex proposals*

7. The major capex investment test is based on assessing the net electricity market benefit (net benefit) of a proposed investment (except for investments that are required to meet the deterministic limb of the grid reliability standards). In order to assess the net benefit, Transpower must estimate the costs and benefits associated with a proposed investment under a demand and generation scenario. While there is the ability within the Capex IM for Transpower to propose alternative demand and generation scenarios, this means that the EDGS must be sufficient in themselves to allow the major capex investment test to be performed. The draft EDGS do not meet this requirement.

8. The ENA's view is that, notwithstanding Transpower's ability to propose alternatives, to meet the purpose of the EDGS in the capex IM, MBIE must develop a range of feasible and reasonable generation and demand scenarios in sufficient detail to allow the major capex investment test to be completed without recourse to additional projections of demand and supply.

9. The alternative is a change (by the Commerce Commission) to Transpower's Capex IM. This would recognise that expending resources on developing and consulting on the regional level of forecast that is required to assess the net benefit of a specific transmission investment is most appropriately done once a need has been identified. The ENA expects that the Commerce Commission would expect Transpower to review or update forecasts at the time it is proposing an investment. The current IM requirements appear to risk duplicating this effort.

10. The draft EDGS have a high level model of demand nationally with some island-level outputs. However, location and peak demand are important when planning grid investments and the ENA submits that without regional and prudent peak demand forecasts the scenarios are incomplete in terms of meeting their current purpose.

11. MBIE appears to have taken the view that because Transpower prepares regional and prudent peak demand projections separately from the EDGS and the Capex IM makes no specific mention of these "separate" projections it "does not have any role in relation to regional or prudent peak demand projections".[2]

12. MBIE appears to acknowledge this lack of completeness in paragraph 48 of the Consultation Guide (emphasis added):

> *we recognise that our approach may result in a disconnect in the process between the EDGS and the Commerce Commission's investment test requirements. Transpower's [sic] may use its judgement in the process and assumptions that create the regional or prudent peak demand forecasts from the EDGS.* ***These forecasts will be a key input to the justification of its investments under the Capex IM.***

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2 See paragraph 47 of the Consultation Guide.

13. It is the ENA's view that however the projections are modelled regional and peak demand are an integral part of the scenarios, and indeed we note that MBIE used several models to develop the rest of the EDGS.

14. There is a link between the draft EDGS and Transpower's regional and prudent peak projections because the EDGS base case demand projection is an input to Tranpower's model and the EDGS use the ratio of peak demand to energy consumption from Transpower's projections at national and North Island level to convert their projection of energy consumption to a peak demand projection. This suggests there is already some level of consistency between the two projections.

15. The ENA suggests that MBIE build on this relationship between the models. A process such as this would allow for independent verification of Transpower's projections. If MBIE chose not to include regional and prudent peak demand projections in the EDGS, Transpower would use its own projections, and a process including consultation for confirming their consistency with the EDGS would be required in any case. It seems likely that it would be lower cost to participants and regulators to complete this process at the same time as consultation on the draft EDGS.

16. The ENA submits that as the residential demand model is "not settled"[3] and regional and prudent peak demand projections have not yet been provided further consultation on the EDGS is required. The ENA suggests that as the exclusion of these projections is a departure from what MBIE proposed in 2012 and therefore unanticipated by participants this delay is not unreasonable. Furthermore, we understand that the EDGS would not be applied immediately as Transpower is not imminently proposing any major capex investments.

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3 Paragraph 84 of the Consultation Guide

3. Modelling and assumptions

17. The ENA recognises that the EDGS cannot cover every conceivable outcome in terms of future electricity demand and generation. However, our view is that the EDGS should be sufficient to enable the major capex investment test to be completed and therefore should capture key uncertainties.

18. Other parties are or have recently undertaken analysis of these uncertainties, and it is not clear from the Consultation Guide to what extent MBIE has had regard to this body of work. For example, the Commerce Commission forecast regional residential, industrial and commercial demand to 2020 in the Default Price-Quality Path reset; MBIE's Smart Grid Forum is undertaking specific analysis of future technology drivers of demand; Business New Zealand is currently developing scenarios to 2050 in a collaborative process. The ENA suggests that the results of these could be used to check the reasonableness and completeness of the EDGS.

19. The ENA is concerned that MBIE has not considered the reasonableness and feasibility of the results of its projection models. These are the criteria for variations to the EDGS proposed by Transpower to be accepted (see clause D4(2)(b) of the Capex IM). The EDGS however do not of themselves appear reasonable and feasible, for example:

    (a) Tauhara Stage Two is modelled in the base case (and many of the variations) to be operational in 2018. This does not seem feasible – Contact Energy's published documents estimate a 42-month development, design and construction timeframe.[4] While the ENA is not aware how much of the development and design work has been completed, we suggest that it is likely that if a 200MW generator was to be fully operational by 2018 the proponent would have confirmed its construction by now.

    (b) It is not clear whether the reasonableness of the exchange rate projections have been verified by an experienced macroeconomic forecaster. Long run averages over the specific 20-year period used by MBIE may not be reasonable, because they may be unduly influenced by particular economic events during that period. Some of the assumed exchange rates appear low relative to more recent rates. This is a critical assumption with regard to high capital cost generation options in particular (such as wind turbines). The ENA suggests that MBIE seek advice from the Treasury regarding an appropriate assumption for long-run exchange rates and other macroeconomic variables.

    (c) We note that the Commerce Commission chose not to use NZIER regional projections of GDP in the 2015 DPP reset because they were concerned at the level of inter-quarter volatility in the level of the projections. It is not clear whether MBIE considered this issue when undertaking its projections and if so how it was resolved.

20. The ENA has not undertaken a detailed analysis of all aspects of the modelling and assumptions, so we raise these as examples rather than a complete list of issues. The ENA suggests that MBIE consider whether the EDGS themselves would meet the test outlined in the Capex IM for variations to the EDGS and where they do not, amend the EDGS.

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4 http://www.contactenergy.co.nz/aboutus/pdf/our_projects/tauhara/CON4401-tauhara-phase-two-geothermal-development.pdf

4. Demand

21. In addition to the comments we have already made about the need for the EDGS to include regional demand projections, the ENA wants to provide some additional comments on the demand projections. There seems to be a mismatch in the level of specificity to which the demand and generation sides of the scenarios are developed and the ENA is concerned that the lack of focus on demand limits the relevance of the scenarios, i.e. they do not represent a reasonable and feasible range of outcomes for demand.

22. The demand scenarios indicate that there is a 100% chance that demand will grow continuously from 2014. The ENA does not think this is a credible result. While it is feasible that the pause in demand growth over the last eight years is an anomaly resulting from the GFC, it is also feasible that demand has been affected by other underlying factors. The scenarios not only predict continuous growth, but allow only a very narrow range of growth across the scenarios given the time horizon of the projections.

23. The implication from these scenarios is that Transpower and distribution companies should be planning for growth and focusing on economies of scale. Under the proposed demand scenarios there is a need for significant investment with only the timing of investments in question. This is not the paradigm ENA members believe they are in. The current reality is significant uncertainty in demand in terms of absolute level, the profile of demand and the mix between residential, commercial and industrial. All these factors can have a dramatic impact on network planning.

24. As we have noted already, the Commerce Commission undertook short to medium term demand forecasts for the purposes of the DPP reset. While these were at the level of distribution the methods and results are still applicable. It is not clear whether MBIE has considered or drawn lessons from this work.

25. The advantage of the approach used in previous MBIE outlook publications of generation scenarios and demand 'sensitivities' was that the level of demand was not locked to a supply scenario. Transpower indicated at the EDGS workshop held by MBIE that it uses a similar approach of considering each generation scenario with each demand scenario. The ENA suggests that MBIE consider whether it is able to separate generation and demand scenarios in a similar manner.

26. The ENA acknowledges that sensitivity analysis is required by the Capex IM at the time a new investment is proposed, including in relation to the level of demand. Nonetheless we consider further analysis of the likely level of demand is needed. We outline some of our concerns below.

4.1 Scenario consistency

27. It is not clear to what extent MBIE has given consideration to the likelihood of a group of assumptions coming to fruition simultaneously, for example it is not clear why the level of solar/electric vehicle (EV) uptake would necessarily be related to the penetration of wind generation. More generally, we are concerned that some of the scenarios are internally inconsistent, in particular the global low carbon emissions scenario and the low demand growth scenario.

28. In the case of the global low carbon emissions, a scenario where there is significant uptake in solar energy and EVs, with high carbon prices, no commensurate increase in energy efficiency is infeasible. Not only should the projection of residential demand per household be the low input in this case, household demand should probably be significantly lower again under this scenario.

29. In the case of low demand growth a state where GDP growth is low and Tiwai load is high is less likely than there being some reduction in Tiwai output. We acknowledge that Tiwai load wouldn't necessarily reduce under every low GDP scenario, but consider that it is more likely than not.

Keeping Tiwai at full output with a conservative estimate of low household demand consumption means the low demand scenario has a higher level of total demand than three other scenarios.

4.2 Consumption and peak demand

30. As MBIE recognises, it is peak demand, rather than throughput that drives the need for investment in transmission capacity. We note that MBIE states that the ratio of peak demand to energy consumption generated by Transpower's "ensemble" model is used to project demand. Given that it is the level of peak demand that is important for grid planning this assumption is important, and it is not clear whether it is based on an historical relationship or is dynamic to future developments. This is important because it is likely that different technology results in a different pattern of demand, for example because of electric vehicle battery or other storage, or because of smart appliances. It is not clear whether MBIE (or Transpower) has given these possibilities any consideration in the EDGS.

31. Some ENBs are reporting or forecasting changes in the profile of demand that are not mirrored in the level of energy use. These changes are due to both energy efficiency measures and so called 'disruptive' technological change. The main technologies that are currently expected to affect the low voltage network are heat pumps, solar panels, electric vehicles and storage.

32. In addition, all the analysis in the EDGS is based on the existing structure of prices. If ENBs choose to move to more demand based pricing (as some already have including The Lines Company and Delta) then this may affect the profile of demand. The Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 mean that as residential consumption declines this is likely to become more attractive. The ENA suggests that MBIE analyse the possible effect of changes in distribution pricing on peak demand.

33. These will be important considerations in developing regional and prudent peak demand projections as part of the EDGS.

4.3 Residential demand

34. The residential demand model for the EDGS has not yet been finalised. We assume from the commentary in the Consultation Guide that the model referred to in the Modelling Guide has not been used. The Modelling Guide indicates that the model is an increasing function of income (real GDP) and a decreasing function of price. This model would appear to conflict with the assumption of the Commerce Commission in the DPP reset of a decrease of 0.8% per user per year.

35. We have attached a report to our submission that the ENA commissioned from Sapere Research Group to provide independent analysis of likely future residential demand as part of the DPP reset. We consider this would be a useful input to the process of understanding the likely range of future residential demand.

36. We are cognisant that in Australia and other jurisdictions, admittedly driven somewhat by feed-in-tariffs, distributed renewable generation has had significant impact on demand, up to 10% on peak periods in Australia. While New Zealand does not feature subsidies for renewable distributed generation the overseas experience highlights that there are tipping points where a change in input costs can have a sizeable effect on demand and network planning. It is increasingly likely that some form of disruptive technology will affect the electricity industry and the impact could be in the relatively short term.

37. In this context and in view of the Sapere analysis, we caution against being too focused on the effects of one or two technologies. While we think that solar is an important technology there are a number of technologies working in concert affecting demand. Energy efficiency may be a more significant factor in the New Zealand context than solar penetration; this is not discussed in the

EDGS. Worldwide most manufacturers are realising that energy efficiency is becoming less a marketing point but rather an expectation of consumers for modern appliances. Energy efficiency targets and standards applied in Europe and America have a direct impact on New Zealand; and energy efficiency is one of the few areas affecting electricity in New Zealand where there are government subsidies and programmes. It is not hard to envisage a tipping point occurring in energy efficiency, and this could already be occurring. In this context, a low demand scenario where average demand per household only falls by 10% over 27 years seems conservative.

38. Notwithstanding our concern that the scenarios are overly focused on the implications of solar and EV technologies, we wish to comment on the analysis of these. The medium (i.e. lower) uptake scenario for EVs suggests that in 25 years less than 4.5% of vehicles will be EVs. This appears very conservative relative to the Business New Zealand scenarios (for example). The ENA notes that the Smart Grid Forum has stated that it has analysed three possible levels of uptake of solar/EV: as in the base case and the "global low carbon emissions" scenario in EDGS and a third "higher uptake trajectory".[5] While the Smart Grid Forum notes that this higher trajectory "falls in the upper ranges of possibility", this suggests that the EDGS do not cover the range of uncertainty in this area. The ENA's view is that this additional scenario should be included in the EDGS. Furthermore the ENA encourages MBIE to consider whether its standard "medium" uptake rate may in fact be a "low" assumption.

39. As noted in section 4.1, the ENA also suggests that MBIE consider the extent to which there is likely to be a link between the level of demand overall and the uptake of solar/EV technologies. There appears to be no link in the current model (i.e. the scenarios in which the level of demand is varied are all based on the lower (medium) uptake path).

40. Analysis from the Smart Grid Forum available on the MBIE website suggests that the uptake of solar is sensitive to the capital cost. If the exchange rate assumption is too low, (depending on the details of how this is modelled) this is a further impetus to increasing levels of uptake relative to the assumptions in the EDGS.

41. We note that MBIE is looking at new models for forecasting residential electricity demand. This reinforces our view, given there is no pressing need for major transmission investment, it is our view that it would be preferable to complete the assessment of new models rather than persevere with demand scenarios that might prove to have a bias.

42. ENBs should be considered an important stakeholder in such assessments. Not only are distribution companies potentially exposed to second order effects from the demand scenarios but they also have insights that simply looking at the ICP level doesn't necessarily achieve. ENBs can assess how diversity affects consumption and profile as load aggregates through the radial network to the GXP.

4.4 Commercial and industrial demand

43. The ENA considers that it is not reasonable for the EDGS projections of commercial and industrial demand to be based on confidential sectoral GDP forecasts prepared by NZIER, as we are unable to comment on these. This effectively means that we do not know how these demands were projected to 2050 and cannot know when the input assumptions cease to reflect the real world. As we noted in section 3, the Commerce Commission chose not to use these forecasts due to volatility in the forecasts.

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[5] Smart Grid Forum scenarios, file note on work to date, November 2014, accessed 4 May 2015, http://www.med.govt.nz/sectors-industries/energy/electricity/new-zealand-smart-grid-forum/meeting-4/workstream-b.pdf

44. Notwithstanding this restriction on our ability to understand the basis of the models, we note that the non-residential forecasts for demand are strongly driven by GDP, which has been the strongest relationship historically. We caution, though, that this relationship depends on changes in energy intensity being less significant than changes in GDP. This may not hold in the future. Indeed, the elasticities shown in the modelling guide for industrial and commercial demand appear high relative to the Commerce Commission's models, which suggests that this relationship may have already changed.

45. To date changes in energy intensity have probably been substantially captured by modelling industrial and commercial demand separately, and especially by the discrete modelling of the large industrials. However, the threshold where businesses are affected by technology change continually reduces as technology costs decline. At the point where industrial and commercial energy intensity becomes significantly affected within each sector then the relationship between GDP and demand could get much weaker and change.

46. The EDGS assume no efficiency improvements across commercial and industrial load. This does not seem to be a reasonable assumption given that EECA has been quoted as saying that savings of $1.6 billion per year are available from process improvements and technology upgrades. The EECA website states that 20% efficiencies are available. In addition, new business models (such as online versus physical stores) may decrease energy intensity regardless of GDP growth. We expect that significant energy efficiency is realisable by industrial and commercial users in the timeframe considered by the EDGS.

47. The ENA's preference would be for a thorough review of the commercial and industrial demand models that considers whether GDP is likely to remain a strong and stable relationship with industrial and commercial electricity demand over the projection horizon. However, at a minimum we suggest that MBIE re-run the analysis of commercial and industrial demand to ensure that the model coefficients have not changed since 2011 and that it understands and can explain differences between its model and the Commerce Commission's more recent analysis.

48. The ENA also suggests that further consideration is given to the manner in which variation in Tiwai load is modelled. It seems likely that by the time the EDGS are used for a major capex investment test there will be more certainty about the level of load at Tiwai. Since this assumption is independent of other parts of demand, and in particular will not affect the demand profile in any other region we agree with MBIE's approach that it should be explicitly modelled. The ENA suggests that consideration be given to modelling Tiwai load as a generation variation as its demand is usually satisfied by the lower South Island generators (e.g. Manapouri and Clyde). This means that lower Tiwai demand would be equivalent to new 'virtual' hydro generation in the lower South Island.

49. The EDGS model demand side response (DSR) and interruptible load (IL) as a generator. All existing DSR and IL is assumed to continue to be used and an additional 100MW of hot water (ripple) IL is assumed to be available in the next ten years. 326MW of DSR is assumed to become available progressively to 2035 with an additional 350MW in the global low carbon emissions scenario. Care is required to ensure that changes in consumer behaviour are not double-counted as DSR. For example, battery storage has potential as DSR, but may already have been considered in the demand profile. The ENA suggests that clear, careful definitions would assist.