

# TPM 2nd issues paper, supplementary consultation

Transpower submission

Transpower New Zealand Limited

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*Keeping the energy flowing*



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## EXECUTIVE SUMMARY

We recommended a simplified, staged alternative (the SSA) to implementing the Electricity Authority's (the Authority's) key proposals, in July 2016. We explained why this alternative would reduce complexity, cost and risk and allow key benefits to be realised sooner. We also set out why this would produce a more durable Transmission Pricing Methodology (TPM) and have the best chance of being implemented to the Authority's desired timeframe.

We are disappointed the SSA proposal was not accepted or advanced as an option. Since our July submission there have been no developments, information or feedback that have caused us to doubt the merits of the SSA or an equivalent approach.

Notwithstanding, our focus remains on helping the Authority reach a satisfactory conclusion to its review of the TPM Guidelines; this is reflected in the content of this submission. Similarly, if the Authority decides to issue new Guidelines, then we will do our best to develop those into a robust, workable and durable TPM.

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### KEY MESSAGES IN THIS SUBMISSION

The 2<sup>nd</sup> Issues paper Supplementary Consultation is a positive step that will help improve the robustness of the Authority's final decision. As we set out in this submission, further refinement is required to give Transpower the flexibility we need to develop a robust, workable and durable TPM.

This submission has the following key points:

1. **To be durable, the Area of Benefit (AoB) needs to be inclusive and time-neutral.** We support broadening the AoB's scope and valuing AoB assets in a time-neutral way. These changes make the AoB more service based and cost reflective and less discriminatory (and simpler to apply).
2. **A peak price signal is essential for an efficient TPM.** We disagree with the Authority's reasoning and position on a peak Long Run Marginal Cost (LRMC) charge. The Authority's current path risks grid over-build and security problems which could swamp any benefits from TPM change.
3. **We support changes to improve flexibility.** We support movements in this direction but consider, in places, the Guidelines err on the side of prescription rather than principle. This risks unintentionally foreclosing development options and adds unnecessary complexity.
4. **On balance the refinements will help Transpower develop a new TPM.** Positive changes include refinements to the prudent discount policy, a wider application of AoB and a time-neutral valuation method.
5. **2020 is not possible for a systems based implementation.** Our current forecast<sup>1</sup>, assuming an April 2017 decision, is for systems implementation for pricing year 1 April 2022. We are exploring whether a transitional (non-systems) implementation is feasible for 2020, and the attendant risks.

As well as expanding on these key points (and others), this submission includes the following documents and evidence:

- **Guidelines commentary:** we have reviewed the draft Guideline and, in Appendix A, provide detailed comment on changes proposed in this latest consultation.

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<sup>1</sup> In December 2016 Transpower established a project team to prepare for a potential decision in April 2017. This timeline reflects that team's preliminary work; it is for the 'realistic' scenario and assumes some further Guidelines improvements.

- We also provide some limited broader comment and suggestions on drafting.<sup>2</sup> In particular, on how to clarify, simplify and generally to improve the standard of the legal drafting.
- **Economic review:** we commissioned an independent economic review of the Supplementary Consultation by Axiom Economics, this is included as Appendix B.
- **Electricity Authority's LRMC working paper:** analysis and comment of the LRMC at Appendix C.
- **Feedback on the Concept Consulting report:** we include additional comment on the Winter Security Margin report (and, for completeness, comments made in November 2016 on the draft of that report) in Appendix D.
- **Distribution Pricing** Our submission to ENA (December 2016) of its review of pricing options, Appendix E.

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### 1. AN INCLUSIVE AND TIME-NEUTRAL AOB CHARGE MAY BE MORE DURABLE AND WORKABLE.

The Authority proposes to extend the scope of the AoB charge, potentially to include the whole grid, and to value AoB investments using a time-neutral methodology. In our view both proposals are critical and should be retained, as they enable:

- the TPM to be more cost reflective and service based, contribute to more efficient price signals and potentially reduce price shock and the scale of wealth transfers;
- more consistent treatment of equivalent assets, reducing concerns of unfair discrimination (on the basis of asset age and location) which could undermine durability;
- less onerous implementation of AoB into asset management, financial and pricing systems than a 'patch-work' application.

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### 2. WE SUPPORT CHANGES THAT IMPROVE FLEXIBILITY AND REMOVE UNNECESSARY COMPLEXITY.

While many of the latest refinements are positive, the changes also add additional complexity to what was already a very complex set of TPM proposals.

We are concerned with the way some of these refinements are dealt with in the draft Guidelines. We consider drafting improvements could improve clarity and flexibility and reduce unnecessary complexity. We discuss these matters in section 2. In our view, The Authority needs to further refine the draft Guidelines to remove unnecessary prescription and complexity.

We consider the draft addendum (appendix A of our July 2016 submission) to be a good example of how major change could be achieved via clear, succinct, principles based (non-prescriptive) Guidelines. Similarly, the 2015 TPM operational review showed the value of targeted, evidence-based, incremental improvements (that can be secured quickly with minimal cost and risk).

We are available to discuss our feedback and to work through drafting suggestions with the Authority team and legal advisers.

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### 3. A PEAK PRICE SIGNAL IS ESSENTIAL FOR AN EFFICIENT TPM.

We appreciate the number of meetings we have had with the Authority on the need for price signals and specifically the role of an LRMC in complementing the 'shadow price' provided by the AoB.

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<sup>2</sup> We do not provide a full 'mark-up' of the draft Guidelines as we did in July 2016. However, most of the suggestions we made in July remain valid now.

However, we have been unable to reconcile our positions. Transpower remains firmly of the view that an LRMC based peak price signal is essential to avoid grid overbuild. Having considered the reasoning in the Supplementary consultation we:

- believe the Authority's position on price signals and LRMC will unnecessarily impose costs on Transpower and consumers through higher than optimal:
  - transmission costs: whether through incremental investment to meet higher GXP level peak demand or the cost of procuring non-transmission solutions
  - energy costs: through increased reliance on peaking generation and the additional costs this imposes on consumers
  - security of supply risks: for the reasons set out in Appendix C, we consider Concept Consulting's assessment of the security of supply risks optimistic.<sup>3</sup>
- consider the Authority places undue reliance on a 'shadow' price signal provided by the AoB charge and do not understand its apparent opposition to an LRMC charge.

We strongly recommend making the LRMC a mandatory requirement of the new TPM. This removes the risk that an LRMC price is not proposed, not prioritised or not accepted into the final TPM.

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#### 4. THE REFINEMENTS ARE ESSENTIAL TO SECURING A ROBUST, WORKABLE AND DURABLE TPM

The Supplementary Consultation includes a number of material improvements to the proposals in the 2<sup>nd</sup> Issues Paper<sup>4</sup>. For example:

- Providing greater flexibility to Transpower in a number of areas including scope of the AoB charges, the method for valuing AoB investments and the design of the residual.
- Improvements to prudent discount policy (PDP) proposals and the introduction of a price cap transition mechanism (although we have substantive concerns about the design of the price cap).
- Deprioritising the marginal savings adjustment mechanism (and removing the least workable component) to an "Additional components" and limiting the scope of the optimisation rule.

These and other improvements are necessary if Transpower is to develop a robust, workable and durable TPM. A key enabler, though, will be ensuring Guideline drafting is clear and provides Transpower sufficient flexibility to apply the provisions in a sensible and workable manner.

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#### 5. 2020 IS NOT POSSIBLE FOR A SYSTEMS IMPLEMENTATION OF A NEW TPM.

Since the review started in 2012 we have focused on the challenges we will face at the conclusion of the Authority's policy (Guidelines) development (stage one). We have, with assistance from PWC, provided a view on implementation timeframes and costs at various points throughout the process. This work has necessarily been heavily caveated because of uncertainty regarding key information, such as:

- The form and content of the Guidelines which fundamentally dictates the size and difficulty of the TPM development and implementation task.

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<sup>3</sup> These, as yet unrecognised, costs could easily swamp any benefits from TPM change.

<sup>4</sup> Available at <http://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c16277>

- The period that Transpower will require to convert Guidelines into a TPM, including to develop and assess options, consultation, legal drafting, cost benefit analysis, price modelling.
- The period the Authority will require to assess Transpower's proposal, including whether part or all the proposal is referred back to Transpower.
- The period Transpower will require to implement the new TPM into pricing systems and then apply in prices to customers.

In relation to the final point, part of the new system will be replacing Transpower's current pricing system which is end of life. The functionality of this system is expected to be required under any new TPM as it essentially exists to apply the connection charge.

In late 2016, after consultation with the Authority and Commerce Commission about the statutory process for funding the work, we established a TPM implementation project. We did this to front-load project establishment and planning and initiate preliminary TPM development work in some areas, to reduce the elapsed time once a final decision was made.

This first stage of the TPM review, the 'Guidelines review', has been underway since 2012. We have reviewed the time needed for the remaining main stages of the process defined in Part 12 of the Code. In broad terms that process and our estimated timings are:

- **Stage 1:** Guidelines review. Subject to specified conditions, the Authority may review the TPM Guidelines. The Authority proposes to issue new Guidelines in April 2017. **Duration: 63 months** (from January 2012 to end April 2017).
- **Stage 2:** Transpower is required to develop the TPM Guidelines into a detailed methodology and submit that TPM, with supporting evidence and materials, to the Authority. This involves identification, assessment and selection of charging options. **Duration: 18 months (Oct. 2018).**
- **Stage 3:** The Authority must consider Transpower proposal and, if the Authority approves that proposal (it may refer part or all of the TPM back to Transpower) it must consult and, after considering submissions, may determine a new TPM. **Duration: 5 months (March 2019).**
- **Stage 4:** Transpower must then implement the new TPM into pricing and related systems and processes such that our customers and the Authority can be assured the TPM is correctly and accurately applied. **Duration: 28 months (April 2021).**

This timeline, which we consider tight but realistic, indicates prices set under new pricing systems would apply from 1 April 2022.

We are aware that this does not meet the Authority's stated objective of new prices taking effect from April 2020. During the consultation period we have discussed with the Authority the possibility of a temporary, non-systems based application of the new TPM as a way to allow prices set under the new TPM to be introduced sooner.

Our recommendations in this submission are conducive to an early implementation. We intend to continue exploring whether a transitional, non-systems implementation could allow prices to take effect from 2020, including to identify and work through potential obstacles with the Authority.

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# 1. INTRODUCTION

We appreciate the opportunity to submit in response to the Electricity Authority's TPM 2<sup>nd</sup> Issues Paper Supplementary Consultation.

We support the Authority adding this step to the TPM review process. The “refinements” include substantial changes to aspects of the TPM proposals.<sup>5</sup>

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## 1.1. THE FOCUS OF OUR SUBMISSIONS

Given the role Transpower would have in developing any new TPM, and the way transmission pricing signals impact on the efficient use and operation of the grid, our focus has been on implementation issues with the proposed new Guidelines.

Our objective has been to try to help achieve a robust and workable TPM. This was reflected, for example, in our proposal for a Simplified Staged Alternative (SSA), and the inclusion of detailed track-changes to the Authority's 2<sup>nd</sup> Issues Paper TPM Guidelines.

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### 1.1.1 TRANSPOWER'S SIMPLIFIED STAGED ALTERNATIVE

The SSA was to help the Authority conclude this contentious and protracted process. The SSA showed that problems with the existing TPM can be dealt with in a proportionate and moderate manner, which avoids unnecessary or radical upheaval. A simpler approach would also bring forward the potential benefits of TPM reform as it would allow for faster implementation.

While stakeholder feedback on our proposal has been positive, the Authority's response has been limited. We consider the passing dismissal of the SSA in the Authority's 13 December 'Q&A'<sup>6</sup> was unsubstantiated. We consider, for the reasons set out in our July 2016 submission, the SSA would better promote the long term interests of consumers than the May 2016 proposal.<sup>7</sup>

We think it would be useful if the quantified cost benefit analysis (CBA) compared the Authority's proposal with both the status quo and principal alternatives such as the SSA, or an LRMC-based TPM (as the consultants Oakley Greenwood modelled for their CBA). This would help ensure the Authority's decision would best meet the statutory objective.

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### 1.1.2 TRACK-CHANGES SUBMISSION TO 2<sup>ND</sup> ISSUES PAPER

In addition to proposing an addendum to the current Guidelines for the SSA, we provided a track-changes version of the Authority's draft Guidelines in our July submission. This was a significant task for Transpower's legal, pricing and engineering teams. On our analysis, these suggestions were rejected or ignored.

We understand this may have been due to administrative oversight by the drafters. We would recommend the Authority reconsider these non-contentious drafting improvements to:

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<sup>5</sup> Within the bounds that beneficiaries-pay (with preference for SPD), removal of any peak-usage charges, and reallocation of HVDC between South Island generators and North Island load have been the constants throughout the review process from the 1<sup>st</sup> Issues Paper onwards.

<sup>6</sup> See: <http://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/development/questions-and-responses/>

<sup>7</sup> As we discussed in our submission on the 2<sup>nd</sup> Issues Paper.

- resolve or avoid unnecessary complexities and problems with the proposed Guidelines (for clarity and help ensure the TPM development process could be completed in a reasonable timeframe)
- remove unnecessary repetition and
- Delete unused definitions.

The majority of the changes we recommended, and the underlying concerns which drove those recommendations, remain applicable to the Supplementary Consultation.

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### 1.1.3 THE DECEMBER 2016 DRAFT GUIDELINES

We remain concerned with the standard of legal drafting in the latest draft Guidelines. We consider the written formulation of the Guidelines to be unnecessarily complicated, uneven and, in places, confusing.

If these issues are not resolved it would make the development stage for a new TPM more difficult, inhibiting our ability to efficiently develop a TPM that best promotes the long-term interests of consumers.

Our preference would be to work with the Authority to resolve our concerns, whether through drafting changes or clarifications. A clause by clause commentary of the current draft Guideline is included at Appendix A. This review was again a substantial exercise for Transpower, however we have not repeated the drafting suggestions we made in July, or provided drafting suggestions alongside all of our clause by clause commentary. We refer the Authority to that earlier advice.

Figure 1: Example of Guideline drafting issues

Drafting of the “overhead and other expenses” clauses

Clauses 5(a)(ii) and 6(b) should be removed. This would remove the following anomalies:

- Clause 5(a)(ii) unnecessarily conflates the definition of "Connection asset" with cost allocation.
- There is overlap and inconsistency between clauses 5(a)(ii) and 6(b) (mandatory components) and clause 47(c) (an additional component, and therefore not mandatory).
- Clause 6(b) does not sit well with 6(a) as it suggests that the "overhead and other expenses that relate to the eligible investment" are separate from "the full cost".

In this instance we consider the draft Guidelines would better achieve their objectives if they simply said:

"Overhead and other expenses should be allocated to the assets they are directly attributable to, to the extent practicable".

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## 1.2. OUR MOST SUBSTANTIVE CONCERNS AT THIS POINT

Our most substantive concerns with the draft Guidelines as they presently stand are:

- **Implementation challenges:** As outlined above, we are concerned about the written formulation of the Guidelines which we consider unnecessarily complicates our ‘stage two’ task of developing the Guideline into a TPM. We also note that, while the revised proposals include a number of substantive improvements, they also add new complexities to the TPM proposals.
- **Expectations about the outcomes under AoB:** The results of application of AoB are highly sensitive to the assumptions and modelling inputs used. For example, the range of outcomes could have an individual customer being determined as a minor or a principal beneficiary.



We believe it is important that market participants understand that indicative prices may change significantly from final prices set under the new TPM.

- **Absence of peak-usage charges:** Too much faith is placed on the AoB charges. AoB can be used to apply a more targeted cost allocation than the current postage stamp and may in some circumstances provide a weak ex-ante price signal. However, it will not (including in conjunction with nodal pricing) provide (efficient) dynamic pricing signals.

We think that removing peak-usage charges (and not replacing the Regional Peak Coincident Charge (RCPD) RCPD with LRMC or LRMC-like charges) at this time would be highly risky and inefficient. Removing peak usage charges ignores ongoing market developments and is inconsistent with the parallel drive for distribution businesses to introduce peak-usage charges based on LRMC. For the distribution pricing reforms to be fully effective any distribution pricing signals need to reflect the LRMC of both distribution and transmission.

We remain of the view that the Authority proposals will risk a rebound Ingrid exit point (GXP) level peak demand, beyond efficient levels. In our view this will flow through to higher costs for Transpower and higher prices for consumers. We discuss this further in Section 3.

- **Wholesale electricity market impacts:** The impact of the AoB charges on generators' spot market offers remains untested and unquantified. The replacement of HVDC on South Island generators with AoB on all generators has several potential implications:
  - It may be inefficient to charge generators on the basis of average injection (clause 17(e)(ii)). Use of average injection would make the AoB charge part of the generators' SRMC (and flow through into offers and cleared prices);
  - These potential distortions to the spot market have not been reflected in the qualitative assessment or the quantified CBA. The SIMI vs HAMI<sup>8</sup> modelling undertaken for the TPM Operational Review<sup>9</sup> shows how this impact could be modelled.
  - The results of applying the price cap could be very different if the Authority's assumption of zero pass-through by generators is removed. If Transpower applied this assumption and it proved wrong it could cause breach of the 3.5% price cap.
- **Breach of the price cap:** While we support transitional provisions, the design of the price cap means Transpower could not provide surety prices would be within the 3.5% retail price cap.

We recommend retaining existing transition provisions or adopting the Commerce Commission approach of linking price increases to the change in network prices (not retail prices).

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### 1.3. ADDITIONAL CONSULTATION STEPS

Further consultation, including on the technical drafting of the Guidelines is necessary to ensure a robust decision is made on the TPM, and to avoid the drafting problems which arose from the DGPP Code Amendments in January.

The Authority signalled it is considering whether an additional conference and cross-submissions should be added to the process.

We strongly support such an initiative. We note:

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<sup>8</sup> South Island Mean Injection, and Historical Anytime Maximum injection, respectively

<sup>9</sup> Available at <https://www.transpower.co.nz/industry/transmission-pricing-methodology-tpm/past-tpm-developments>

- The proposals are now substantially different from the 1<sup>st</sup> Issues Paper proposals that were dealt with at the 2012 conference
- In our view conferences should be a standard part of any contentious policy changes (as reflected by Commerce Commission practice)
- Waiting until after submissions to decide whether to seek cross-submissions is sub-optimal (it unnecessarily creates workload planning difficulties for the Authority and stakeholders and delays the process).

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## 2. THE CHANGES TO THE AUTHORITY'S PROPOSALS

In this section we comment on the refinements set out in the Supplementary Consultation. We outline that, while the substantive changes are positive, the increasing level of complexity creates further implementation challenges.

We acknowledge positively the Authority's openness to refining its proposals, and that it has taken on board aspects of our submissions.

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### 2.1 WE SUPPORT MANY OF THE SUBSTANTIVE REFINEMENTS

The draft TPM Guidelines in the Supplementary Consultation move away from prescription towards principle based guidance and increased flexibility. We support this movement and consider the substantive changes to be positive. However, we note the changes add new complexities to an already complex TPM proposal.

We discuss below further refinements we consider would be desirable to get the balance between prescription and flexibility right. We recognise this is not an easy balancing act and trade-offs are necessary. We also summarise below the positive changes we consider the Authority has made to its May 2016 proposals and what we see as the additional complexities or red-flag issues which need to be ironed out.

In summary, we consider that:

- The Authority has made some positive changes to the balance between flexibility and prescription although we would support further refinement to get this balance right
- Some of the guiding principles that apply where the Authority is giving Transpower greater flexibility could be usefully improved
- There are a number of substantive improvements to the version of the Guidelines proposed in the 2<sup>nd</sup> Issues Paper
- The concerns we have raised in our July 2016 submission and in this paper need to be resolved prior to a final decision on the TPM. If not resolved they will add substantial time and resource to the TPM development process.

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### 2.2 GETTING THE LEVEL OF FLEXIBILITY IN THE GUIDELINES RIGHT

The Supplementary Consultation makes clear the Authority's intention is to "increase the flexibility for Transpower ...", with the Guidelines leaving a large number of issues for Transpower to resolve.

The increased flexibility is most evident from a comparison with the 1<sup>st</sup> Issues Paper proposal which, for example, prescribed that Transpower was required to develop an SPD methodology to the proposals in the 2<sup>nd</sup> Issues Paper, and the Supplementary Consultation, which prescribe that Transpower is required to set develop an "area-of-benefit" (AoB) charge, but is silent on the method required to calculate benefit.

We support the Authority's efforts to increase the flexibility of the Guidelines. This will help mitigate the risk, once Transpower and stakeholders begin to convert the Guidelines into a new methodology, of unintended consequences or unintentionally foreclosing options that may better promote the long-term benefit of consumers.

While we acknowledge the shift towards more flexibility we think further refinement would be beneficial. For example, the flexibility provided to Transpower versus the level of prescription in the proposed Guidelines is quite uneven within the Guidelines. Some of the principles the Authority proposes would also benefit from refinement.

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### 2.2.1 FLEXIBILITY VERSUS PRESCRIPTION

As an example, the residual charge provisions **provide** that the residual charge may be historical anytime maximum demand or “another method”, and prescribe some principles to be followed in determining what that method may be. In contrast, for the AoB charge, if it is not practicable to apportion the AoB charges based on relative benefit, the proposed Guidelines **prescribe** that charges to generation customers “must be on the basis of each customer’s average injection”.<sup>10</sup>

We consider that it would be preferable if the method for allocating AoB charges to generation were determined as part of the development of the new or amended TPM. This would be consistent with the current Guidelines and the approach that we took to reviewing the HVDC charges as part of our 2014/15 Operational Review.

#### Potential for unintended consequences

While the 2014/15 review determined, on the basis of quantified evidence, that average injection was a more efficient allocator than peak injection for the HVDC, a different conclusion may be reached in relation to the AoB charges. This is because:

- The current average injection charge is difficult for South Island generators to pass-through into higher wholesale electricity market prices because South Island generators do not always set the clearing price (and their North Island competitors do not incur the HVDC charge)
- However, the circumstances are very different in relation to the AoB charges. Each generator would incur AoB charges, including the generation plant that sets the clearing price. That could mean an average injection charge results in substantial static inefficiencies.

Whether those inefficiencies would be greater or smaller than those arising from other methods is an empirical question that has not been addressed by the Authority in the review process. We consider that quantified analysis, such as that undertaken for the 2014/15 Operational Review is necessary before the optimum allocator can be determined.

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### 2.2.2 DIRECTION BY WAY OF GUIDING PRINCIPLES

In areas where the Authority has reduced the level of prescription, it has provided guiding principles to assist Transpower to determine what the best approach should be. We support this approach.

However, some of the guiding principles could be refined to remove ambiguity. For example, the new clause requiring that “Transpower must weigh the economic benefits of sending accurate price signals against the economic costs of developing and administering the relevant method” may well just confuse matters (clause 12).

The residual charge provides a further example of where we think the guiding principles could be improved.

Our understanding is that the principal criterion for the residual charge is that it be set in a way which is as fixed/unavoidable or incentive-free as practicable. This is reflected in clause 32(d). We support this principle.

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<sup>10</sup> Charges to load must be on the same basis of the residual (which we think makes sense, and is determined by Transpower).

However, the guiding principles extend beyond this in ways which aren't necessarily helpful or efficient.

- The reference to correcting for double counting and other charging anomalies (clause 32(b)) appears to be specific to the Authority's own modelling of indicative prices and seems unnecessary. Transpower should avoid double counting and other charging anomalies in all aspects of its pricing, not just the residual. There is also an inconsistency between the Supplementary Consultation and the draft Guidelines. The Supplementary Consultation requires that Transpower "must ... seek to avoid double counting and other charging anomalies" [emphasis added].<sup>11</sup> The draft Guidelines require that the residual charge "must ... correct for" without this qualification.
- We are unclear about the distinction which is intended between clauses 32(a) and (e). They both require that the residual must be based on load.
- Clauses 32(a) and (e) may also conflict with clause 32(d). For example, clauses 32(a) and (e) would be satisfied by setting the Residual Charge on a MWh basis, but this would conflict with clause 32(d).
- Whether charges are "broadly equivalent" (clause 32(c)) depends on the measure "broadly equivalent circumstances". It will inevitably be the case that charges which are "broadly equivalent" in some "circumstances" will fail to be equivalent in other "circumstances" e.g. a charge based on AMD could mean that two EDBs with very different volume of electricity consumption could pay the same amount. If, tautologically, "broadly equivalent circumstances" is defined as peak demand the clause would be complied with. If total load is used to define "broadly equivalent circumstances" the clause would be violated.

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### 2.2.3 SOME CHANGES RISK NOT ACHIEVING THEIR INTENT

Clauses 14 and 15 appear to have been added to address submitter concern that the challenges with calculating private benefits go well beyond accuracy. Specifically, that results are highly sensitive to the assumptions and modelling inputs used (the range of outcomes could potentially have an individual customer being determined as a minor or a principal beneficiary).

The new clause allowing Transpower to take "the average of the benefits under two or more likely scenarios" (clause 14) does not resolve issues with calculating private benefits (the Guidelines don't need an explicit clause to enable Transpower to model multiple scenarios anyway). Nor does the new clause providing for Transpower to "apply to the Authority for a determination as to whether the assumptions that Transpower proposes to adopt are reasonable" (clause 15).

However, we note that the latter option may help Transpower where different assumptions or modelling scenarios would produce substantial different wealth transfer outcomes amongst our customers though, as it would allow Transpower to delegate such contentious judgements to the Authority. It would also assist if the clause applied more generally to the method used to calculate AoB, and not just instances where clause 14 has been applied.

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## 2.3 POSITIVE CHANGES TO THE MAY 2016 PROPOSALS

We comment briefly below on changes that we consider to be improvements on the Authority's May 2016 proposals.

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<sup>11</sup> Electricity Authority, TPM Second issues paper, Supplementary consultation, 13 December 2016, paragraph 3.125.

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### 2.3.1 AN INCLUSIVE, TIME-NEUTRAL AOB CHARGE

We support the Authority's proposals to:

- Allow a wider application of the AoB (clause 47(h))
- Remove the proposals to require different and discriminatory valuation methods between sunk and new AoB investments and
- Allow a time-neutral valuation of the assets or investments to which the AoB is applied (clause 27).

This changes may help ameliorate the concerns of some submitters that the AoB charges would be discriminatory and result in a situation where load customers in the UNI swing from paying 'too little' (based on the Authority's problem definition) to a situation where those customers pay 'too much'.

In our view this will enable the AoB and the TPM to be:

1. **More cost reflective and service based:** allowing for most, or all of the entire grid to be included, allowing for the prices to reflect to underlying cost of providing services to customers in different locations.<sup>12</sup> This change makes the TPM fundamentally more cost reflective and service based than the May 2016 proposal.  
  
An LRM based price signal would complement the AoB charge, providing for a cost reflective, service based charge with efficient forward looking (ex-ante) price signals.
2. **More consistent:** by allowing for more consistent treatment of grid assets and investments across the country and over time (in contrast to earlier proposals, in which the AoB was highly selective, applying to a small part of grid and had different rules for valuing assets);
3. **More simple to implement and administer:** somewhat counter-intuitively, a more inclusive AoB is likely to be simpler to implement and considerably more efficient to administer than the May 2016 proposal.
4. **Less discriminatory and more durable:** an inclusive and time neutral AoB charge treats customers in fundamentally the same way (it does not arbitrarily discriminate between customers on the basis of location or asset age) so is therefore likely to be considered objectively fairer, and therefore more durable.

These changes are, in our view, essential for the durability and workability of the AoB charge.

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### 2.3.2 FLEXIBILITY TO NET LRM REVENUES OFF AOB CHARGES

We support removal of the prescription that any revenue from LRM charges must be netted off the Residual Charge. Also, providing Transpower the flexibility, "If an LRM charge is included in the TPM", that "the TPM must specify a method for adjusting charges under the TPM to take into account revenue recovered by the LRM charge" (clause 50).

Our reasons for supporting this change are detailed in full in our submission on the 2<sup>nd</sup> Issues Paper. In summary, it avoids the potential situation where customers may incur LRM charges reflecting the forward-looking cost of future investment, and then incurs the cost of that investment in full through AoB charges. The result could be recovery of more than the full cost of the investment i.e. excessive profits on the particular asset (which would artificially suppress charges for other assets).

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<sup>12</sup> In particular, when the connection charge framework (which is complementary) is also taken into account.

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### 2.3.3 ALLOCATION TO INJECTION VS OFFTAKE CUSTOMERS

We support removal of the requirement that AoB charges to generation and load must be allocated so that each group is allocated charges that correspond to the proportion of aggregate benefits the group is expected to receive.

We consider that these clauses were unnecessary and redundant.

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### 2.3.4 RELEGATION OF THE MARGINAL SAVINGS ADJUSTMENT MECHANISM

We support the narrowing of the marginal savings adjustment mechanism, and relegating it as an “additional component” (clause 47(f)).

Our submission on the 2<sup>nd</sup> Issues Paper detailed concerns about the workability of the ‘marginal savings’ mechanism, and risk of negative unintended consequences.<sup>13</sup> The narrowing of the scope of the mechanism removes a component that would have had no practical effect.

The analysis in our submission on the 2<sup>nd</sup> Issues Paper, and in other submissions, suggests there would be practical issues that may not be resolvable. Based on this, we consider that it would be better to remove the clause from the Guidelines altogether.

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### 2.3.5 REFINEMENT OF PRUDENT DISCOUNT AND OPTIMISATION PROVISIONS

The revised Guidelines include a number of refinements and improvements to the prudent discount and optimisation provisions which we support:

- The removal of the proposed PDP provisions for consumers exiting the market.
- Not requiring the distributor to “build generation” to receive a PDP where DG could make it privately beneficial to inefficiently disconnect from the interconnection grid.
- The removal of the condition that a PDP might apply to an embedded load customer of a distributor whose charges exceed stand-alone cost.
- The clarification that optimisation would only be available for high value investments. We note optimisation would be redundant if AoB meet the DMEF definition of beneficiaries-pay.

We consider that these provisions could be improved further still by either removing the optimisation requirements altogether, noting that Transpower would need to consider whether the valuation methodology that applied to AoB assets would be an optimised value anyway (if this was more cost reflective and service based), or moving the optimisation provisions to an additional component. We note that if we determined, under clauses 26 – 28, the valuation method should be an optimised method this could render clauses 20 – 24 and clause 30 redundant.<sup>14</sup>

If the optimisation provisions are retained, or moved to an additional component, we consider that they should be amended to be less prescriptive about when optimisation would apply, and to remove the arbitrary thresholds that are proposed (specifically, the threshold that “a single customer disconnects from the grid causing the optimised value of the asset to reduce by more than 20%; and ... the optimised value of the asset is less than 80% of the non-optimised value of the asset” (clause 21(b))). The Authority has not explained or justified these thresholds.

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<sup>13</sup> Transpower submission: TPM 2<sup>nd</sup> Issues and Proposals Paper, 26 July 2016, page 33.

<sup>14</sup> Applying an optimised valuation methodology would mean optimisation would apply in all instances not just when the clause 21(b) thresholds held. An optimised valuation methodology could also alter the time profile of area-of-benefit charges over an investment’s remaining expected life.

## 2.4 CONCERNS ABOUT ADDED COMPLEXITY

While we support most of the Authority's refinements to its May 2016 proposals we are also concerned about the added complexity the refinements bring to an already very complicated set of proposals.

We comment briefly on what we see as the main sources of additional complexity and share our thoughts on how this complexity could be contained (or avoided). We are unclear about the benefit of adding new complexity given the Authority view that "the effect of most of the refinements ... apart from the cap on load parties is likely to be modest".<sup>15</sup>

Table 1 Additional complexities with Supplementary Consultation

Examples of additional new complexities	
1	Clause 12 (and clause 29): It is unclear how the trade-off between the efficiency of accurate price signals and simplicity can be balanced given we consider that, to the extent that the AoB charges would send any signal at all, the AoB would send inefficient price signals.
2	<p>Clause 30: The requirement to alter the time profile of AoB charges over an investment's remaining expected life would impose another layer or dimension to the complexity of applying AoB.</p> <p>We do recognise, though, the threshold that the result must be "manifestly inconsistent with the services provided ... at different times in the life of the investment". This qualification helps ameliorate the potential challenges with applying the clause i.e. absent the "manifestly inconsistent" qualification the clause could potentially apply to all AoB investments/</p>
3	<p>Residual charge, clause 32(b): Under clause 32 "The method for calculating the residual charge must ... (b) correct for double counting and other charging anomalies; and (c) result in broadly equivalent charges to customers that are in broadly equivalent circumstances ...".</p> <p>This is a good example where the qualification "to the extent practicable" or "reasonably practicable" is needed. The Supplementary Consultation reflects this qualification, and its description of the proposal conflicts with the actual Guideline drafting.</p>
4	Residual charge, clause 32(c): Whether charges are "broadly equivalent" depends on the measure "broadly equivalent circumstances". It will inevitably be the case that charges which are "broadly equivalent" in some "circumstances" will fail to be equivalent in other "circumstances" e.g. a charge based on AMD could mean that two EDBs with very different volume of electricity consumption could pay the same amount. If, tautologically, "broadly equivalent circumstances" is defined as peak demand the clause would be complied with. If total load is used to define "broadly equivalent circumstances" the clause would be violated.

<sup>15</sup> Electricity Authority, TPM Second issues paper, Supplementary consultation, 13 December 2016, paragraph 5.42.



5	<p>Clauses 34 – 36: The Authority proposes that “If a large consumer chose to shift its supplier from Transpower or a distributor to another supplier (whether Transpower or another distributor), the AoB and residual charges it paid to the original supplier would shift with it”.<sup>16</sup> While this would be straightforward in relation to a direct connect customer embedding into an EDB, there would be practical problems with the reverse (a large consumer directly connecting to Transpower), or a large consumer switching from one EDB to another. This is because the AoB and residual charges Transpower would have to impose on EDBs is set at an aggregate level. The amount that can be attributed to a particular large consumer is simply unknown.</p>
6	<p>Price cap, clause 55: Clause 55 would require Transpower to estimate the “total of the electricity bills (including all charges in respect of transmission, distribution, energy, levies, and taxes)” of each of the distributor’s customers, and each direct customer, for 2019/20, and how each of these (not just the transmission component) would change in the subsequent year.</p> <p>Transpower would be required to do this at the time it submitted a new TPM for the Authority to approve (as the Code requires that the new TPM be accompanied with indicative prices), and at the time Transpower implemented the new TPM.</p> <p>Depending on when Transpower submitted a proposed new TPM, e.g. if it was prior to 2019/2020, Transpower would have to make a series of speculative judgements including the impact of the Commerce Commission’s 2020 price reset for both Transpower and each EDB, and what changes would occur to wholesale and retail prices. Even if this were done on an ex post basis, to do it properly would require information that is not in the commercial domain e.g. each electricity retailers’ revenue divided by each EDB area, and each direct connect customer.<sup>17</sup></p>
7	<p>Clause 61: The price cap provisions would require Transpower to calculate the incremental cost of supply to each customer the cap could apply to.</p>

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<sup>16</sup> Electricity Authority, TPM Second issues paper, Supplementary consultation, 13 December 2016, paragraph 3.138.

<sup>17</sup> In relation to direct connect customers, if this information was obtained from their retailers, and the price cap was applied, it would be possible to work backward to determine what the (commercially-sensitive) retail prices they are receiving are.

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## 3 PEAK SIGNAL A KEY ELEMENT OF AN EFFICIENT TPM

In this section we focus on one of our most substantive concerns with the Authority's TPM proposals. Specifically, to completely remove any ex-ante peak pricing signals from the TPM.

We are concerned that making LPMC an 'additional component' presents unnecessary and asymmetric risk relative to making the LPMC a mandatory element of the TPM.

Our strong preference is that the Authority requires Transpower to develop an LPMC charge.

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### 3.3 THE CASE FOR AN LPMC CHARGE

We consider the case for including an LPMC charge has already been made by Transpower and other submitters. We do not consider this to be controversial.

The Authority has said that it is for Transpower to make the case for introducing an LPMC charge (which is expected to provide an ex-ante peak price signal).

We understand this position and agree an LPMC charge, like any part of the TPM, should be objectively justified and demonstrably efficient.

However, we consider that making LPMC an additional component is likely to lead to unintended consequences and expose Transpower, the sector and consumers to adverse outcomes (higher costs and risk). We consider those risks are unnecessary and asymmetric (i.e. there is no corresponding upside).

We discuss these points briefly below and also explain why we see LPMC as a complement to the AoB charge, not a rival.

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#### 3.3.1 RISK OF UNINTENDED CONSEQUENCES

We are concerned that the draft Guidelines may give rise to unintended consequences. We consider the following to be material risks:

1. **An LPMC charge is not proposed, prioritised or accepted into the final TPM.** Developing an LPMC charge is not a trivial task and, in prioritising TPM development tasks, we will be required to focus on mandatory elements. In assessing non-mandatory elements, we will have to form a view about the likely success of any LPMC proposal. Our perception is that the Authority is unduly critical and unlikely to be receptive to an LPMC proposal.

The consequence of an LPMC not being implemented as part of a new TPM would, in our view, be a material increase in risk and costs across the power system and prices for consumers.

2. **Regulatory uncertainty.** A peak price signal has been an enduring part of the TPM for many years.

We are well aware that these TPM Guidelines closely follow changes to the DGPPs and interact with distribution pricing reforms. We are concerned about the market impact of uncertainty around whether there will be a peak price signal compounding uncertainty about the future of the DGPP regime. We are also concerned this change will disrupt parallel efforts to reform

distribution pricing (and have concern at the lack of regulatory coordination between these important and interdependent initiatives).<sup>18</sup>

As we have previously submitted, we do not know what the impact of fundamental changes to the DGPPs and TPM will change market participant behaviour. However, we know that those participants currently combine to reduce peak demand on the grid by approximately one fifth (~1300MW).

Even a relatively small change in response could have significant impacts on the level of reliability, system security and prices faced by consumers.

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### 3.3.2 RISKS ARE ASYMMETRIC AND UNNECESSARY

We consider these risks to be asymmetric and unfavourable to consumers. That is because:

1. **The cost and risk of making LRM C a mandatory component is small.** Because the Authority would have to approve any LRM C charge that Transpower develops there should be no risk that Transpower introduces a charge the EA is uncomfortable with.

In developing a TPM we would work through the various design options, taking account of the Authority's LRM C working paper, and conduct cost benefit analysis.

2. **The cost and risk of leaving LRM C as an additional component is potentially very high.** That is because there is a real risk that an LRM C charge is simply not developed (for the reasons discussed above) and / or that uncertainty over whether the TPM will contain a peak signal inefficiently alters decisions by other market participants.

We also consider the risk to be unnecessary. That is because, as outlined in point 1 about, the Authority can easily mitigate the risk by making the LRM C charge a mandatory requirement of the new TPM.

Our strong preference is that the Authority makes this change to the draft Guideline. We consider the only constraint on the development of the LRM C charge, should mirror that provided for in clause 6 of the existing Guidelines (2006).

*"Nodal pricing is a key component of transmission pricing, which Transpower should take into account when preparing its proposed TPM."*

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## 3.4 LRM C AN OPPORTUNITY TO CORRECT PROBLEMS WITH RCPD

We share the Authority's view that the current regional coincident peak demand (RCPD) charge is highly likely to be sending over-strong pricing signals in some areas.

The Authority has detailed the potential for perverse outcomes that could arise from this. The problem arises from the existing requirement for the *entire interconnection cost* to be recovered through the RCPD. We consider the problem can be dealt with simply by allowing cost recovery through two-part tariffs: with a combination of LRM C-based peak-usage pricing signals, and 'fixed' charges to recover the remainder of Transpower's revenue requirement.

In essence, we believe that an LRM C charge would complement any AoB cost allocation, not substitute for it.

We detail below that:

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<sup>18</sup> Approximately 70% of costs recovered under the current TPM are recovered via distribution charges.

- We consider LRMC and AoB should not be treated as rivals or substitutes, and doing so has not helped the latter parts of the TPM review.
- The emergence of new technologies strengthens the case for peak pricing.
- Distribution and transmission pricing should operate in unison to signal the over cost of peak-usage on electricity network investment.

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### 3.4.1 LRMC AND AOB ARE COMPLEMENTS (NOT RIVALS)

We consider that LRMC and AoB are complements, not rivals.

We are concerned that, during this process the functions of cost allocation and price signalling have been conflated. We consider that AoB and LRMC have separate, by complementary and supportive, roles:

1. The primary or exclusive role of the AoB method should be to ensure a more targeted (the Authority uses the terms “service-based” and “cost-reflective”) allocation of costs amongst regions or areas-of-benefit. This would displace the current postage-stamp cost allocation.
2. The AoB cost allocation is then recovered through a two-part tariff: a combination of an LRMC-based peak-usage charges, and a ‘fixed’ residual charges.

Together these would replace the existing RCPD and/or HVDC charges.

We consider the Authority’s assessment of LRMC pricing from the LRMC Working Paper<sup>19</sup> provided an orthodox analysis of LRMC which noted it was dynamically-efficient, nodal pricing was limited to short-term pricing signals only, and LRMC was market-like.<sup>20</sup>

The evolution of beneficiaries-pay and LRMC from potential complements to now being depicted as rivals is unfortunate. We refer the Authority back to the analysis it undertook of LRMC in the LRMC working paper, including the limits on the role of nodal pricing.

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### 3.4.2 THE IMPACT OF EMERGING TECHNOLOGY

When this review started in 2012 the focus was on large capacity expanding generation and transmission projects and, while an economic downturn had impacted demand, expectations were for a return to normal.

Contrast that with 2017, the focus is very different and participants across the sector are grappling with and trying to positioning themselves for success as we anticipate widespread disruption from emerging technologies. It is likely that the Authority’s 2012 specification of a material change in circumstance is out of date.

When viewed through this lens we consider careful consideration is needed of the implications of emerging technology for transmission (and for transmission pricing), which has parallel potential implications for electricity transmission as it does for electricity distribution.

In particular, demand for electricity is changing (flattening) and we are starting to see the impact of emerging, or evolving, technology. We agree with the Authority’s comment that “Evolving technologies will affect the operation of, and/or investment in, distribution networks ...”<sup>21</sup> and

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<sup>19</sup> Available at <http://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/consultations/#c16277>

<sup>20</sup> Refer to Appendix C for a discussion of the Authority’s position on LRMC and nodal pricing in the LRMC working paper.

<sup>21</sup> Electricity Authority, Implications of evolving technologies for pricing of distribution services, Consultation Paper, 3 November 2015, paragraph 3.2.1.

consider this also applies to transmission. We agree too with the Authority's comment that "The appropriate pricing structure ... depends on a range of factors including:

- whether the network has only just enough capacity to cope with consumer demand (when it is at its peak) or has substantial spare capacity
- whether consumer demand on any given network is growing or shrinking ..."<sup>22</sup>.

The electricity sector is transitioning from a world where demand for electricity predictably increased with population and GDP, to one where peak and total energy demand are much less predictable.

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### 3.4.3 WHAT DOES THIS MEAN FOR NETWORK ASSETS (AND FOR PRICING)?

One of the implications of emerging technology is that the economic life of capacity driven investments may be substantially less than the engineering life of the assets.

The key implication of this for pricing is that the shorter the economic life, the higher the effective LPMC of a new investment. In this context the benefits of peak-usage charges are not limited to the efficient deferral of transmission investment (a substantial benefit in its own right) but potentially avoiding the need for the investment altogether.

The Authority has recognised the importance of emerging technologies in relation to distribution pricing (including the need for peak or time-of-use pricing). In our view, emerging technologies have similar implications for transmission pricing.

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### 3.4.4 LINKAGES BETWEEN DISTRIBUTION AND TRANSMISSION PRICING

In our view:

- The conclusions the Authority has reached on the impact of emerging technology for electricity distribution pricing are also valid for transmission pricing i.e. emerging technology means there should be greater reliance on peak-usage and LPMC pricing.
- The electricity distribution and transmission reviews have been siloed up until now but need to be brought together; particularly as the benefits to an electricity distributor of adopting peak-usage charges depends, in turn, on the extent to which they incur transmission costs on a peak-usage basis. RCPD currently forms the basis of part of some EDBs own peak-usage charges.

Last year, we submitted to the Authority on the importance of policy coherence amongst electricity distribution pricing, the distributed generation pricing principles and the TPM.<sup>23</sup> Our subsequent submission to ENA, on distribution pricing, had a similar focus: trying to align EDBs, the Authority, Transpower and other stakeholders on complementary, approaches to electricity distribution and transmission pricing.<sup>24</sup>

This focus reflected our concern that these major changes for the sector have been largely siloed and the risk that these could diverge or even move in opposite directions. We consider this to be a genuine risk that, in our view, would be counter-productive and inefficient. We would like distribution and transmission pricing to reinforce and complement each other.

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<sup>22</sup> Electricity Authority, Implications of evolving technologies for pricing of distribution services, Consultation Paper, 3 November 2015, page F.

<sup>23</sup> Transpower, submission to the Electricity Authority, Distribution pricing review, 2 February 2016. See Appendix E.

<sup>24</sup> Our submission to ENA is attached, and should be treated as part of this submission.

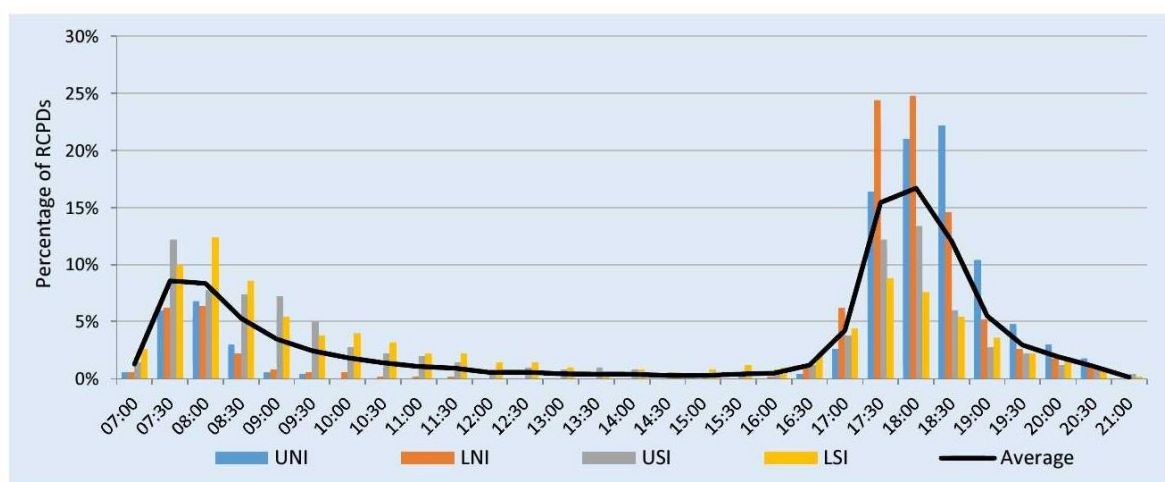
## Support ENA work and see strong parallels for TPM

We support work by the ENA on distribution pricing. In our view, the justification ENA has provided for LRMC-based peak-usage charges, and the like, are valid and apply equally to transmission.

An end-user making decisions about whether to consume peak or off-peak should face price signals which reflect the cost of both the distribution and transmission networks, with distribution and transmission pricing complementing each other. Our position is reinforced by the data ENA references which "... suggests a strong correlation between transmission and distribution network peak demand periods".<sup>25</sup> This is supported by Figure 24 in the ENA consultation paper, replicated below.

Figure 2 Reproduced diagram of regional transmission peaks, ENA consultation (refer footnote 24)

**Figure 24: Regional transmission peaks by time of day**



Source: ENA analysis of Transpower data

The types of tariff reform under consideration would be complemented and supported by retention of a peak price signal in the TPM. For example, time of use distribution tariffs and a transmission peak charge (e.g. an LRMC-based) to work in a complementary and self-reinforcing manner.

## Transpower submission to the ENA distribution pricing consultation

Transpower submitted to the ENA consultation. We have enclosed our submission at Appendix E. A theme of our submission was the need for coordination and coherence between transmission, distribution and DG pricing.

In broad terms we share views expressed by the ENA, in its November consultation paper, about the link between cost-reflectivity, the role of pricing in managing future investment requirements, and how LRMC-based pricing promotes dynamic efficiency.

<sup>25</sup> ENA, New Pricing Options for Electricity Distributors, A discussion paper for industry feedback, November 2016, page 39.

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## 4 TRANSITIONAL ARRANGEMENTS TO DEAL WITH PRICE SHOCKS

In this section we comment on the Authority's proposed price cap transition mechanism. We support in principle the inclusion of a price cap although we have concerns with the Authority's proposed design.

We consider a less prescriptive approach would avoid the risk of unintended consequences. We recommend that the Authority retain the requirement on Transpower to consider transitional arrangements to mitigate price shocks in the current (2006) Guidelines.

Alternatively, the Authority could adopt the Commerce Commission's practice of capping price increases with reference to the regulated prices in question (transmission), rather than linking to retail prices.

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### 4.1 SUPPORT FOR REQUIREMENT TO CONSIDER TRANSITION PROVISIONS

The process to date has shown the potential for very large transfers, some of which have the potential to affect the viability of enterprise or the economic wellbeing of residential consumers.

We consider there to be a need to include or retain transition provisions in the TPM Guidelines. We are open to the inclusion of a price cap. However, we have a number of practical and substantive concerns with the design of the price cap and its expression in the draft Guidelines.

We discuss below some of alternative transitional provisions that the Authority could consider. A key theme is trying to keep these principles based, to avoid over-prescription which could foreclose consideration of superior alternatives in due course (when we have better clarity on the actual TPM and price impacts).

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#### 4.1.1 PRINCIPLES BASED (NON-PRESCRIPTIVE) APPROACHES TO TRANSITIONAL PROVISIONS

We raised concerns with aspects of the prudent discount proposals in the 2<sup>nd</sup> Issues paper. We support changes made in this area in the Supplementary Consultation.

We understand and support the Authority's proposal for transitional provisions to mitigate impacts of adverse price changes. We have carefully considered the Authority's specific price-cap proposal. We consider that the practical and substantive concerns we have identified could be largely avoided if the Authority adopted a less prescriptive and more principles based approach, as it has done elsewhere in the draft Guidelines.

A principles based approach would allow the Authority to provide confidence to affected parties without prescribing a specific methodology before the actual impacts are understood. We explore some potential approaches below:

1. **Retain transition provisions specified in Clause 19 of the current TPM Guidelines.** Clause 19 requires that:

"Overall transitional arrangements should be proposed where revision of the methodology leads to large increases or decreases in current charges".

We consider that this approach would allow the Authority to assure parties who are potentially adversely affected that Transpower will be required to propose transitional arrangements where changes to the TPM lead to large price changes.

It would avoid the risk the Authority currently faces (of trying to design a prescriptive solution before the nature and size of the problem is understood) and allow Transpower to consider a full range of options, including to take account of regulatory precedent and other considerations.

We are not aware of any concerns being raised with clause 19 as it presently stands.

2. **Apply a weighted average of the existing and new TPM during transition.** This would be consistent with the approach adopted by the Authority in its 2015 decision to change the HVDC allocator from HAMI to SIMI which uses a weighted average of the two during the transition.

If combined with an absolute cap (see option 3) this could also allow the Authority to assure parties who are potentially adversely affected that prices will not rise by no more than a percentage to be determined by the Authority.

We consider this approach could potentially be effective, though is likely to raise practical challenges and is somewhat prescriptive. We are not aware of any concerns being raised about the HAMI to SIMI transition.

3. **Apply a Commerce Commission like approach to mitigating price shocks.** This would allow the Authority to specify upfront that transmission costs will not increase by no more than a percentage to be determined by the Authority.

This approach is transparent and very simple to apply. A further benefit of this approach is consistency with the other electricity sector regulator, the Commerce Commission. The Commission applies this approach routinely when setting network prices for gas and electricity services under Part 4 of the Commerce Act. The approach adopted by the Commission to “minimise price shocks to consumers”<sup>26</sup> provides precedent that is equally applicable for addressing price shocks caused by TPM changes.

The Commission’s approach involves a price cap on network charges (rather than on total electricity bills) which is transparent and very simple to apply. The Commission has tended to cap price increases at 5%<sup>27</sup> or 10%<sup>28</sup> of distribution network costs, equivalent to 1% to 2% of retail prices or, in transmission price terms, an increase of roughly 10% to 20%.

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<sup>26</sup> As required by sections 53D (3) and 53(P)(8)(a) in Part 4 of the Commerce Act.

<sup>27</sup> The Commerce Commission used a cap of CPI + 10% on distribution charges (excluding pass-through and recoverable costs) in the initial price resets for both electricity and gas. The Commerce Commission subsequently lowered the cap for price shocks from 10% to 5%. Notably, this is net of pass-through and recoverable costs (including cost of transmission) so the actual percentage cap on total distribution charges would be substantially less than 10% or 5%.

<sup>28</sup> For the 2010-15 EDB DPP mid-period reset the Commerce Commission capped price increases at CPI + 10% [Commerce Commission, Resetting the 2010-15 Default Price-Quality Paths for 16 Electricity Distributors, 30 November 2012, paragraph 6.3]. The Commerce Commission adopted the same approach for the 2013-17 gas reset but “No alternative rates of change were necessary or desirable for price shocks because all the increases are below the CPI+10% level we have previously used as an indicator of price shock” [Commerce Commission, Setting Default Price-Quality Paths for Suppliers of Gas Pipeline Services Date, 28 February 2013, paragraph 3.13].

Notably “None of the submissions raised a concern with using 10% as an indication of a price shock” [Commerce Commission, Resetting the 2010-15 Default Price-Quality Paths for 16 Electricity Distributors, 30 November 2012, paragraph 6.3] and “The limit on price changes reflects the fact that year-on-year price increases that exceed CPI+10% are undesirable for an essential service” [Commerce Commission, Resetting the 2010-15 Default Price-Quality Paths for 16 Electricity Distributors, 30 November 2012, paragraph 6.7]. “Vector noted in its submission that they strive to limit price increases of regulated services to a maximum of 10%. Price increases above this level could be seen as creating hardship for consumers” [Commerce Commission, 2010-15 Default Price-Quality Path Starting Price Adjustments and Other Amendments, Update paper, April 2011, paragraph 6.15].



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## 4.2 CONCERNS WITH PRICE CAP DESIGN

While we fully support transitional provisions and are open to a price cap we have practical and substantive concerns with the design of the Authority's price cap proposal. We discuss these concerns below.

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### 4.2.1 PRACTICAL CONSIDERATIONS

During the consultation period we tried to apply the price cap. The purpose of this was to:

1. Help us understand the Authority's policy and modelling
2. Identify information and / or practical challenges to implementing the price-cap
3. Identify errors in inputs, assumptions or model design
4. Understand, in transmission charge terms, what the 3.5% retail price cap means.

In summary, we found the price cap very difficult to apply in practice. Specifically, we found information, sequencing and other practical issues for which we could not find an obvious solution. We also found a number of compounding errors in the Authority's modelling<sup>29</sup>.

Some examples of the issues or challenges we identified are outlined below. In the interests of brevity, we have omitted our analysis and detailed findings. We would be happy to brief the Authority on this analysis and our detailed findings.

#### Examples of practical issues and challenges arising from price-cap design

In order to implement the new TPM by April 2020, with the proposed price cap Transpower would need to:

1. know the Commission's default and individual price paths reset decisions (scheduled for end of November 2019). We note that:
  - 2019 will be the first application of the new TPM. We do not know how this process will operate but expect the timeframes to be very constrained, with extraordinary assurance (audit and governance) requirements
  - In addition to applying the TPM for the first time we will need to obtain, understand and process 2015/16 pricing information for 29 EDBs (including (i) regulated EDBs and (ii) non-regulated EDBs). We are unsure when this information will be available.
2. estimate the retail component of electricity charges in each EDB network area, and for each direct connect customer. We do not expect this information to be readily available and therefore will have to be estimated. We consider that estimating the retail component of electricity charges in each EDB area would require a number of forecasting assumptions such as the level of pass-through of network charge changes by electricity retailers, and the impact of the AoB charges on spot prices. We consider that, due to the value implications, this estimation is potentially contentious.
3. calculate the incremental cost of supplying EDBs and direct connect customers that would be subject to the cap.
4. complete this analysis, quality assurance and governance processes, within a one-month window between November 2019 (when the Commission's price reset decision is known) and

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<sup>29</sup> These relate primarily to the WACC and revenue estimation assumptions. The effect of these errors is to understate how widely, and the extent to which prices are modelled to exceed the cap.

December 2019 when Transpower is required to notify its customers of the April 2020 price changes.

An April 2020 date would entail additional complexity and estimation. That is because Transpower would need to estimate both retail prices for the 2019/20 year (which would only be partially complete) as well as 2020/21. This would mean the risks of the price cap of 3.5% being breached would be higher if the TPM was implemented April 2020 compared to any future date.

Any errors Transpower made in estimating and forecasting retail prices could result in breach of the retail cap. For example, the retail cap could be breached if:

- Transpower assumed 100% immediate pass-through of network charge reductions by retailers (and assumption the Authority made), but pass-through was less than 100%
- AoB charges to generators had a greater impact on spot market prices than assumed by the Authority (0%) or Transpower.

The design of the price-cap appears to hardcode the implementation date for the new TPM. We query whether this is consistent with the process specified in the Code (which requires the Authority to determine an implementation date after it determines the TPM and after consulting with Transpower<sup>30</sup>).

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#### 4.2.2 SUBSTANTIVE MATTERS

The proposed design of the price cap (setting aside the level of the cap) has a number of problems. For example, the proposed design would:

- **Create uncertainty for consumers.** This uncertainty is caused by a number of factors. For example, the size of the change in transmission charges, during the transition, would depend on (1) the size of any Part 4 price reset changes, (2) the mix of consumer types in different network areas (and the design of distribution tariffs), (3) energy, retail and other costs.
- **Potentially undermines the effect of Commerce Commission determinations.** By creating an inverse relationship between the Commerce Commission's starting price adjustments (price resets) and changes in TPM charges i.e. the greater the reduction in prices, as part of the Commerce Commission's Part 4 reset, the higher the increases in transmission charges that could arise.

This could be seen as undermining the benefits to consumers from the Commerce Commission's operation of Part 4.

- **Unnecessarily increase TPM implementation costs.** The costs to Transpower and participants to implement and apply the price-cap as designed are likely to be significant relative to alternatives. This is in part driven by the complexity of the design and in part due to the information requirements and likely need for extensive forecasting and estimation.

Further, we consider the potentially large value implications of price-cap implementation will make this forecasting and estimation contentious (precluding 'rough and ready' approximation and or necessitating the added complexity of 'wash-up' provisions so under or over charging is corrected ex post).<sup>31</sup>

This information limitation introduced above is highlighted by the Authority's adoption of an assumption that the average retail rate is 77% of the average residential retail rate. The 77% is then

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<sup>30</sup> Code 12.94

<sup>31</sup> With additional complexity where retailers offer discounts for bundled services e.g. gas and electricity or gas, electricity and telecommunications combined.

applied across all EDBs. However, this number will be different, depending on the customer mix, for each distribution network.

The table below shows that where the 77% is an overestimate the price cap will be breached, for example if the actual rate is 60%, then using a 'one size fits all' rate would mean a retail movement of 4.49%. Only when the actual rate is higher will the price movement be below 3.5%.

Actual Average Retail Rate of a Distribution Lines Service Area	Effective Cap
90% of residential retail rates	2.99%
85% of residential retail rates	3.17%
80% of residential retail rates	3.37%
77% of residential retail rates	3.50%
75% of residential retail rates	3.59%
70% of residential retail rates	3.85%
65% of residential retail rates	4.15%
60% of residential retail rates	4.49%
55% of residential retail rates	4.90%
50% of residential retail rates	5.39%
45% of residential retail rates	5.99%
40% of residential retail rates	6.74%

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## 5 IMPLEMENTATION TIMELINE

In this section we describe, in broad terms, our assessment of the expected process from the issuing of TPM Guidelines to prices under a new TPM being set for the first time.

The Authority has indicated a preference for prices to be in place for the pricing year commencing 1 April 2020 (PY20/21) and has asked Transpower how we might expedite development and implementation of a new TPM.

We conclude that we are unlikely to implement a new TPM into pricing systems and processes until mid-2021, which means prices under the new TPM will come into effect in 2022 at the earliest. We consider a transitional, non-systems based, implementation may be feasible from 2020.

We also summarise discussions with the Authority and Commerce Commission regarding the costs of implementation, preliminary work undertaken by Transpower and our current views on implementation timeframes.

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### 5.1 PROJECT ESTABLISHMENT AND PRELIMINARY DEVELOPMENT WORK

In December 2016 Transpower established a project to begin scoping a potential TPM implementation project.

We did this to help understand likely implementation challenges and timelines and to front-load 'low-regrets' project establishment and planning work (with the aim of reducing elapsed time once a final decision was made).

While this work remains in its early stages it has allowed us to form firmer, though still preliminary, views on the process and likely timeframes for developing, obtaining approval for, and implementing a new TPM.

We summarise our preliminary views below.

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### 5.2 MEETING THE COSTS OF DEVELOPMENT AND IMPLEMENTATION

Transpower is subject to economic regulation by the Commission under Part 4 of the Commerce Act. We are subject to incentive regulation and the main instrument for regulating the quality and cost of Transpower's services is known as the 'individual price path' (IPP). The IPP is set once every five years. The threshold for 're-opening' the IPP is, for good reason, very high.

#### Transpower's current IPP

When the current, 2015-2020 IPP was set the Commission expressly excluded the costs of developing and implementing a new TPM from Transpower. It did this:

1. On the advice of the Electricity Authority, due to uncertainty about whether the TPM would be changed and, if it were changed, the timing and cost implications of those changes.
2. Cognisant of provisions in the primary legislation that explicitly provide for the Commission, in certain circumstances, to amend Transpower's IPP at the request of the Authority.

Transpower recognised these uncertainties and agreed with the position arrived at by the Commission under advice from the Authority.

## Section 54V of the Commerce Act

Section 54V of the Commerce Act allows for the Commerce Commission to reopen Transpower's individual price path (IPP), under some specific circumstances, on the request of the Authority.

We recognise that uncertainty remains over whether the Authority will eventually decide to change the TPM Guideline, and the consequential costs implications for Transpower. However, we are mindful of the potential for uncertainty over cost recovery to delay the implementation by Transpower of any Authority decision to change the TPM Guidelines.

To reduce the risk of that delay occurring Transpower sought clarity on the section 54V process ahead of a final decision by the Authority. We also sought confirmation that costs incurred in advance of a final decision could be recovered. For example, to begin scoping a TPM implementation project to better understand project costs and timelines.

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### 5.3 PROCESS OVERVIEW

The process of reviewing the TPM Guidelines and then the TPM has four broad stages:

- **Stage 1:** Guidelines review. Subject to specified conditions, the Authority may review the TPM Guidelines. At the end of that process it may new TPM Guidelines. This is what the Authority proposes to do in April 2017. **Duration: 63 months** (from January 2012 to end April 2017).
- **Stage 2:** Transpower is required to develop the TPM Guidelines into a detailed methodology and submit that TPM, with supporting evidence and materials, to the Authority. This involves identification, assessment and selection of charging options. **Duration: 18 months (October 2018).**
- **Stage 3:** The Authority must consider Transpower proposal and, if the Authority approves that proposal (it may refer part or all of the TPM back to Transpower) it must consult and, after considering submissions, may determine a new TPM. **Duration: 5 months (March 2019).**
- **Stage 4:** Transpower must then implement the new TPM into pricing and related systems and processes such that our customers and the Authority can be assured the TPM is correctly and accurately applied. **Duration: 28 months (April 2021).**

This first stage, the Authority's 'Guidelines review', has been underway since 2012 and is expected to conclude in April 2017. At that point Transpower will be required to convert the TPM Guidelines into a detailed methodology. This second stage, TPM development, has been the focus of our planning so far although we have also estimated elapsed time for stages 3 and 4.

A detailed project plan will not be possible until the final Guidelines are issued and, as the Authority process has shown, timelines are not guaranteed.

Since December our primary focus has been on responding to the Supplementary Consultation and implementing new obligations on Transpower arising from the 6 December DGPP decision<sup>32</sup>.

However, we have established a project and filled some key roles. This has allowed high level planning to start and we have formed preliminary views on the overall project timetable.

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<sup>32</sup> Available at <http://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/review-part-6-dg-pricing-principles/development/authority-decision-on-the-review-of-dgpps-and-acot/>

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### 5.3.1 IDENTIFYING STAGE AND PROJECT CRITICAL PATHS

Given the limited time available and competing priorities, our approach to the planning, has been to try to map a project critical path based on what we expect will be the most time intensive element of each stage. In summary, we:

- **Focussed primarily on stage two.** which in project terminology is referred to as the “requirements phase”, where we consider developing, assessing and designing AoB charge options will be the most time (and resource) intensive task. We:
  - mapped an indicative (if somewhat optimistic) process, based on our understanding of the task we will be required to complete and our view of what is robust consultation
  - Include limited time at the start and end of the AoB development work to (i) complete project establishment, administrative and governance arrangements (etc.) (ii) complete necessary documentation, quality assurance and governance processes prior to submission of our [overall] TPM proposal to the Authority.
- **Provides a placeholder for stage three.** This placeholder (five months) is based on hybrid between the timeline provided in the Code (for the Authority to review, approve, consult on and determine a new TPM) and what we experienced with the 2014/15 TPM operational review, which followed that process.

We consider that this time allowance is plausible but challenging (with potentially material delay risk).

- **Maps a semi-generic IT project for stage four.** Recognising the scope of this task remains materially unclear we have mapped the generic process for an IT systems project of moderate complexity. This stage is the least well specified at this point.

Our planning work should be considered preliminary. However, we consider it to be the most informed and robust view that we have presented to date.

Our work produces different results to earlier estimates by PWC, though these differences are reconcilable – relating in broad terms to direction by Transpower to (i) assume stage 2 will be limited to 12 months (this was essentially a placeholder) (ii) adopt the optimistic, rather than pessimistic or realistic, timeframes for stages 3 and 4.<sup>33</sup>

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### 5.3.2 JULY 2021 TO COMPLETE SYSTEMS IMPLEMENTATION

Our conclusion is that a realistic date for implementation of a new TPM into pricing systems and processes would be July 2021, flowing through into customer prices from 2022.

We have shared our preliminary views on implementation timing with the Authority and intend to continue working with the Authority to refine these. We include snapshots and a high level explanation of the main stages below.

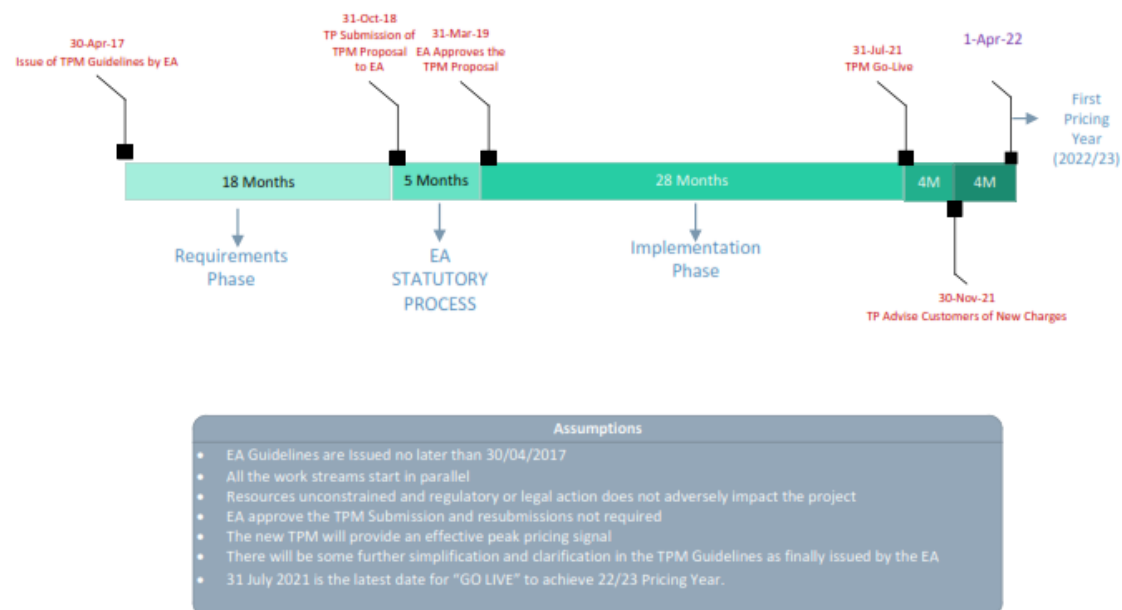
#### Process from Guidelines decision to completion of systems implementation

Figure 3 provides an overview of the main stages from Guideline decision to implementation in pricing systems (and in customer prices the following April).

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<sup>33</sup> This optimism bias effectively ‘banked’ the timetable benefits of a high risk approach though does not account for the costs or potential downsides of a higher risk approach (e.g. legal risk if stage 3 process is deficient or cost/time overruns if shortcuts backfire or other problems emerge in stage 3).

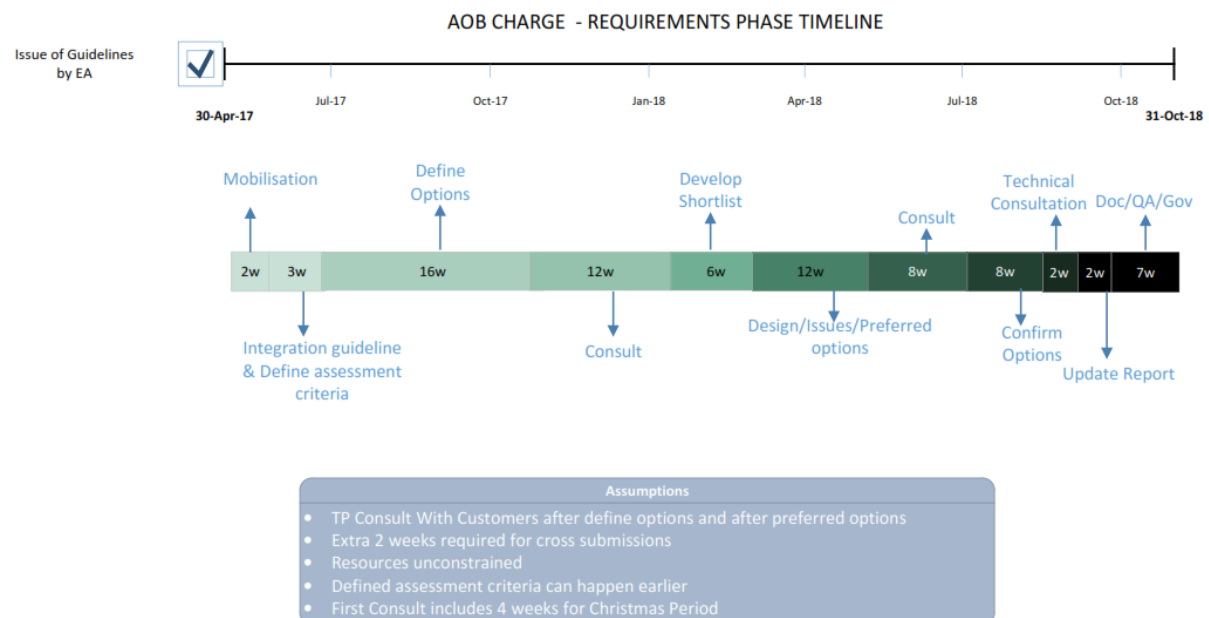
Figure 3: Implementation project overview (preliminary view)



## Stage two: critical path strawman for development of AoB charge

Figure 4 shows our strawman critical path for developing the AoB charge elements in the Guidelines. We consider this is likely to be the most challenging and time intensive task in developing the Guidelines into a TPM.

Figure 4: AoB charge development for 'requirements phase' (preliminary view)



We have begun a similar exercise for the other main elements but have had to pause this work while we complete our submission to the Supplementary Consultation. We identify the other main elements as:

1. LRMC charge
2. Connection charge
3. Residual charge

4. Prudent discount / optimisation
5. Transition / price cap
6. Additional components

Some of these elements are potentially of similar complexity to the AoB charge development.

We assume development will run concurrently. We are working through how best to package and stage development and consultation processes. We intend to utilise a variety of consultation techniques with the objective of gaining as much benefit for as little impact on stakeholders as possible.

We intend to consult on the process we plan to run shortly after the Authority issues a final decision, assuming that decision is to change the TPM Guidelines.

### Stage three: timeline for EA approval of Transpower's proposed TPM

We assess the minimum realistic time for the Authority to review, approve, consult and determine a new TPM based on the process specified in the Code is approximately four months.

In February 2015 Transpower proposed a number of changes to the TPM. The elapsed time to final decision was approximately six months. For planning purposes, we assume five months for completion of stage three.

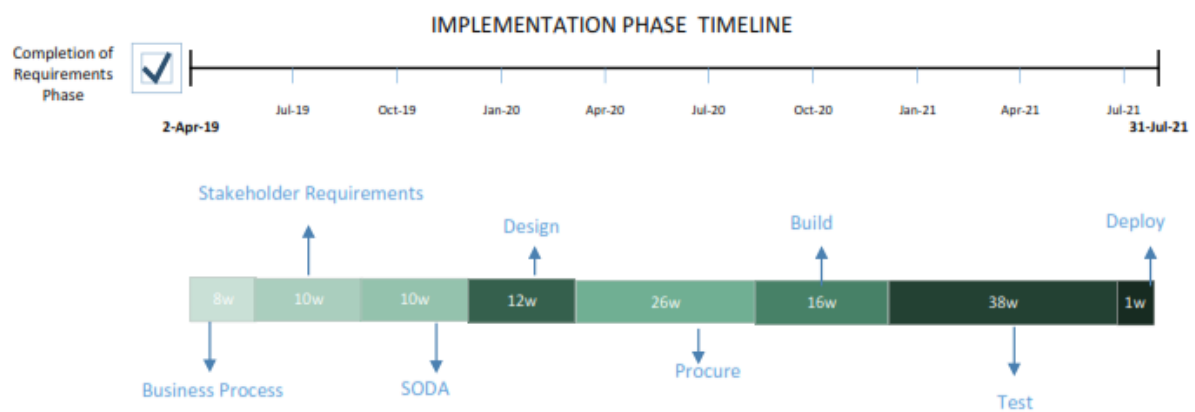
We note that, while preparatory work for stage four can occur prior to completion of stage three, this is likely to increase project cost and risk.

### Stage four: indicative timeline for systems implementation of AoB charge

Substantial uncertainty remains over exactly what systems development will be required. We are assuming that there will be a moderately complicated IT systems project to integrate new and existing elements of the TPM into a robust pricing system.

Figure 5 shows the timeline we have developed for a semi-generic project of this nature.

Figure 5: Indicative timeline for systems implementation phase (stage four)



### Integrating a new TPM into Transpower's pricing processes

The TPM recovers Transpower's regulated revenues, as determined by the Commission under Part 4 of the Commerce Act. In summary, Transpower sets prices annually in December for the pricing year commencing on 1 April the following year. Table 2 summarises the main steps:



Table 2: Overview of key steps in current TPM annual pricing round

Task	Description	Dates
Prepare Asset Information in Asset Register	Work with project teams to finalise the value of projects as at the end of our financial year. Translate assets into pricing building blocks and ensure all records reconcile across systems and reports. During the pricing period the asset register is closed to facilitate the integrity of the financial and pricing audits	June – early August
Reconcile Pricing and Accounting Systems	Ensure the value and description of assets within the asset register and pricing system reconcile. Define asset links and recovery methods. Update reports to illustrate asset configuration and pricing building block information	Early August – early September
Close Capacity Measurement Year	Load final capacity figures, post market reconciliation, into meter data repository. Review any permitted meter data changes (e.g. EOCs or paralleling events). Extract customer capacity information and load capacity information into pricing system to enable connection asset allocation	Early September - mid September
Consult Customers with Capacity and Asset Information	Share capacity and asset reports with customers and work together to ensure the data being used to determine their prices matches their expectations. Explain where differences may occur (e.g. work not completed following the close of the financial year, the impact of changes by another customer)	Mid-September – late September
Review Differences and Anomalies	Assess reasons where the pricing system is not performing as expected due to anomalies or in accordance with contract terms, to ensure assets are recovered in accordance with the prevailing TPM or contract	Mid-September – late September
Engage Auditors	Work with auditors to ensure adherence to TPM. Where differences or anomalies occur, they are justified and sufficiently documented.	Late September – mid November
Update Revenue	Compare ex-post revenue building block calculation to the number forecast before the start of the Regulatory Control Period. The difference is the annual wash-up which together with the incentive credit/debit is added to the forecast revenue for the following pricing year. This process and figure is audited, published on our website and sent to the Commerce Commission for review and issue a formal determination on.	Early July – early November
Determine Costs	Obtain and reconcile maintenance spend and allocate this across asset types. Allocate asset costs to connection and interconnection and determine the associated depreciation and net book value amounts. Prorate shared assets as required	Mid-September – Mid October
Determine Prices	Translate cost, revenue, capacity and asset information into prices. Translate information into meaningful reports to illustrate any changes that may have occurred	Mid October- late October
Board Approves Prices	Follow appropriate governance by ensuring adequate management signoff during the drafting of the pricing board paper. Seek board ratification of the rates.	Early to mid-November
Pricing Notification	Prepare customer pricing packs to illustrate the new rates and update their transmission agreement schedule. Advise customers, the Commerce Commission and the Authority of the new rates.	Early to late November

In oWe are required to notify customers of prices three months prior to the start of the pricing year on 1 April, although our practice has been to do this in late November or early December in consideration of our customers' and their customers' needs.

### Relative difficulty of applying elements within the current TPM

Under the current TPM there are three charges: the HVDC, interconnection and connection charges:

- **The interconnection and HVDC charges are straightforward to calculate:** we estimate these comprise less than 10% of the effort currently expended on the annual pricing round.

Timelines: determination of interconnection and HVDC charges cannot start until the end of the capacity measurement period (31 August). The interconnection charge cannot be finalised until connection charges are confirmed (as interconnection revenue = total revenue – HVDC revenue – connection charges).

- **The connection charge is a data intensive exercise with multiple human interventions:**<sup>34</sup> we estimate that 90+% of effort relates to the connection charge which involves the granular allocation of individual assets to individual customers.

Timelines: determination of the connection charge cannot start until late July (when financial process to confirm the grid at June 30 are complete) and cannot be finalised until customer verification (September/October) and independent audit (November) are completed.

### Comparison with the Authority's proposal

Under the Authority's proposal the relatively straight forward HVDC and interconnection charges would be removed. They would be replaced with an AoB charge, a residual charge and (if the Authority accepts Transpower's recommendation) an LRMC charge.

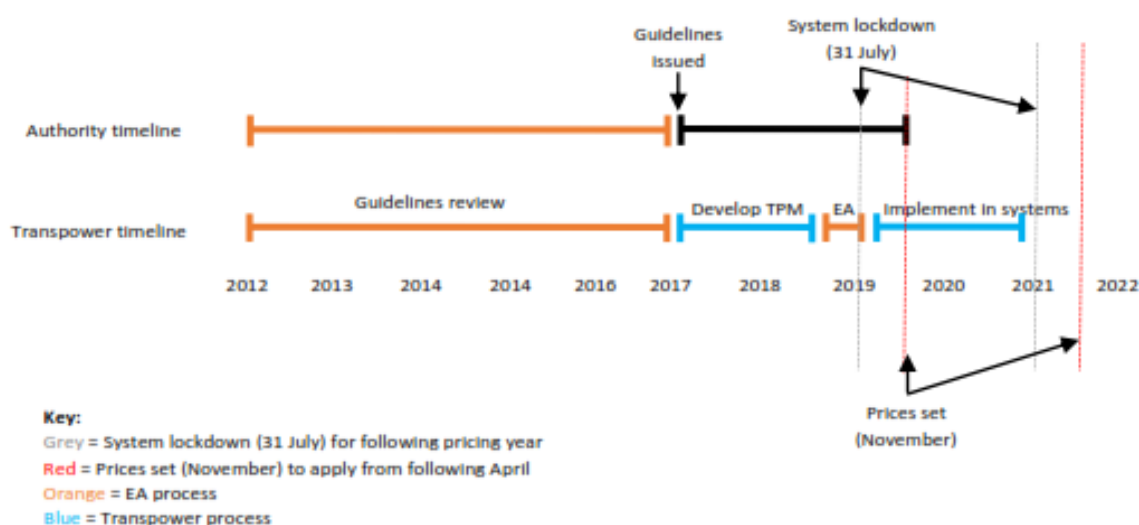
There are a number of additional one-off or ongoing processes, such as the price cap, that will need to occur in parallel or at when the main pricing process is completed. In our assessment:

- The residual and LRMC charges would be similar in application complexity to the HVDC or interconnection charge.
- The AoB may share some attributes with the current connection charge though will, we expect, be broader in scope, more complex and involved to apply.

### Relevance for changes to the TPM

Figure 6 shows how this process is expected to relate to the implementation of a new TPM. It shows when system lockdown would need to occur so prices could be set to apply from 1 April the following year for (i) 2020 and (ii) 2022 (for the Authority's and Transpower estimated timelines).

Figure 6: Integration of new TPM into pricing processes



<sup>34</sup> By Transpower's finance and pricing teams, our customers (verification) and our auditors.

In our planning we assume that pricing systems need to be locked down by 31 July, at the latest, to allow the pricing round to proceed. This allows prices to be approved by Transpower's Board in November and notified to customers<sup>35</sup> in late November or December (after final processing is completed and pricing packs are prepared).

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## 5.4 POTENTIAL FOR TRANSITIONAL IMPLEMENTATION IN 2020?

The Authority has been clear that it would like prices set under the new TPM to apply from 2020. For the reasons set out above, it is not realistic to expect the new TPM to be implemented in new pricing systems by July 2019.

However, we are currently exploring whether a transitional, non-systems based implementation could allow new TPM prices to apply from 2020 and, if so, what limitations might apply.

At this point we consider this approach might involve utilisation of the current pricing system for connection charges coupled with a non-systems implementation of the new components of the TPM.

We consider this should be achievable, though will depend on the design of the new TPM (it may not be possible to deliver a robust solution for the 2019 pricing round if the TPM is at the very complex end of the spectrum) and assurance requirements.

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### 5.4.1 PROPOSE TO EXPLORE FURTHER WITH AUTHORITY AND STAKEHOLDERS

We propose to develop our preliminary thinking on the possibility of a transitional, non-systems based, implementation for 2020. We intend to explore this option further with the Authority.

We also welcome views on this option from stakeholders – either directly (via your customer representative or the regulatory and pricing team) and / or, if cross-submissions are sought or a conference scheduled, through that channel.

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<sup>35</sup> Transpower also notifies, with Director certification, the Commerce Commission and the Authority that it has set prices in accordance with the TPM and Part 4 of the Commerce Act.

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## 6 NEXT STEPS AND OTHER MATTERS

The first stage of the TPM review process has been protracted. We would like this stage to conclude in a timely manner and to complete the subsequent stages as expeditiously as possible.

We consider that finding a timely and satisfactory resolution to this ongoing review process is a strategic priority. We are concerned about the direct and opportunity costs this process has and continues to impose on the Authority, Transpower and our respect stakeholders and customers.

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### 6.1 WE WILL CONTINUE TO ASSIST THE AUTHORITY

We intend to continue to assist the Authority as it considers submissions and formulates its decision. In particular, should the Authority consider it of value, we can:

- Continue to provide information, analysis and technical advice;
- Work with the Authority and its legal advisers to resolve technical drafting issues in the Guidelines;
- Prepare for the next stage in this review process, including project planning, confirming funding and establish procedural and governance arrangements;
- Expand on or discuss any matter raised in this or prior Transpower submissions.

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#### 6.1.1 THE SSA SHOULD STILL BE ON THE TABLE

Our intent to assist the Authority includes exploration of Transpower's July 2016 SSA proposal.

The Supplementary Consultation does not engage on our SSA proposal, though we note the Authority's view conclusion in the question and answers published on 13 December:

"We've given considerable thought to Transpower's 'simplified staged' approach and do not agree it is a lower risk and more durable approach. A fundamental requirement for durability is that only parties that benefit from grid assets are charged for those assets. This does not apply for key elements of Transpower's simplified approach.

Although Transpower's approach is simpler than the Authority's proposal, it isn't consistent with the Authority's decision-making and economic framework, and therefore would be easily challenged in the courts."

We respectfully disagree with the view expressed above. We do not know the status of our proposal but consider that it should still be on the table.

In our view, the SSA proposal is the most durable and most likely to promote the long term interests of consumers of the alternatives currently before the Authority. We also consider the proposal scores higher on the Authority's decision making and economic framework than the Authority's own proposal. However, in any event, we do not agree that the relative ranking on the DMEF should or would particularly affect exposure to successful legal challenge

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### 6.2 OTHER MATTERS

In this submission we have focused on the current consultation and, with a few exceptions, not repeated concerns raised by Transpower or other submitters in prior submissions. However, we consider many of those concerns remain and, regardless of whether the Authority adopts our SSA,

we strongly encourage the Authority to pay careful attention to concerns raised (in response to prior consultations by the Authority by Transpower and other submitters as it formulates its final decision.

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### 6.2.1 COST BENEFIT ANALYSIS

We have not engaged on the Oakley Greenwood response to criticism of its work but we have been unimpressed by OGW's response which we do not consider gives adequate regard to what appear to be valid submitter concerns with the standard of its work.

We would encourage the CBA to compare not just the Authority's proposal with the status quo but to compare it with alternatives such as Transpower's SSA.

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### 6.2.2 PEER REVIEW

The Authority has not commissioned peer review by an independent expert. This practice is common amongst regulators, in particular for complex and controversial matters such as this. For example:

- The Authority commissioned a peer review (by Dr Darryl Biggar) of the transmission pricing advisory group (TPAG) report on transmission pricing;
- The Commerce Commission routinely commissions peer review of its work, including of its expert reports and the reports of submitters.

The Authority's proposals have been widely criticised. On many of the issues under debate it is difficult to discern between valid criticism and self-interest and it can be tempting to dismiss criticism as misunderstanding or 'sour grapes'.

We consider that peer review could both help the Authority sanity check its thinking in a contained and impartial way and would help reassure stakeholders.

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## 6.3 POTENTIAL IMPLICATIONS OF TPM CHANGES FOR THE DGPP REGIME

The Authority stated, in the DGPP Decisions and Reasons Paper, that "The proposed new TPM would allow Transpower to introduce an LRMC charge" and, if this change occurs, "the new ACOT arrangements might no longer be needed, or require refinement".<sup>36</sup>

The Authority went on to suggest "If the TPM guidelines change, then in parallel with submitting a new TPM to the Authority for approval, Transpower should also recommend to the Authority further adjustments to the DGPPs that will promote efficiency and competitive neutrality between demand response, distributed generation and grid-connected generation".<sup>37</sup>

We are not sure that it is necessary to wait until submitting a new TPM for approval to outline our views on the implications for the DGPPs. We have already expressed our views about how the TPM and DGPPs should interrelate.

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### 6.3.1 OUR BASIC POSITION ON THE DGPPS

Our submissions have made it clear we consider:

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<sup>36</sup> Electricity Authority, Review of distributed generation pricing principles, Decisions and reasons, 6 December 2016, Executive Summary.

<sup>37</sup> Electricity Authority, Review of distributed generation pricing principles, Decisions and reasons, 6 December 2016, Executive Summary.

- For any transmission pricing signal to be fully effective it needs to reach end-users and DG;
- The difference between avoided charges and avoided costs is a problem with the TPM, not the DGPPs; and
- Replacement of the current RCPD charges with LRMC or LRMC-like charges would remedy this problem.

If LRMC or LRMC-like charges are included in the TPM the Authority could simply reverse the Code Amendments introduced in January 2017.

Our comments are focused on the efficiency of avoided cost of transmission payments to DG. More broadly we consider improvements could be made to the DGPPs, for example to clarify and to make the principles technology neutral.

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### 6.3.2 IMPLICATIONS OF INTRODUCTION OF AOB

One potential issue with the TPM proposals for DG is that, depending on its design, the AoB could result in unintended consequences and anomalies. That is because the operation of distributed generation could reduce the calculated benefits any given direct-connect customer receives from an eligible investment.

For example:

There are areas of the country where, if consented generation were built, DG would be more than sufficient to meet its peak-demand. In that scenario, the benefit the local distributor receives from the transmission grid, or any individual eligible investment, would be substantially reduced. The avoided AOB charge, arising from DG, could be substantial.

The Authority has assumed that the AoB “shadow prices” would impact on consumer behaviour before an investment is made. Putting aside our views on that issue, we consider AoB charges are highly likely to impact behaviour after they have been introduced to recover the cost of sunk assets.

It is very plausible that the “ACOT problem” would be worse under AoB than with RCPD. At least RCPD over-signals to reduce peak-usage, which can lower or delay transmission investment needs (even if it does so inefficiently). The ACOT problem under AoB would be about avoiding a share of AoB charges for sunk investment.

The Authority acknowledges, to a certain degree, the distortion AoB would cause in the DGPP Decisions and Reasons Paper:

“The basis for calculating avoided AOB charges is not entirely clear, but would presumably involve some assessment of how AOB charges would have differed in the absence of distributed generation. Given that the initial set of AOB charges is to recover the costs for historical transmission investments, it is not clear that ACOT amounts calculated in this way would necessarily provide efficient signals to distributed generation”.<sup>38</sup>

It was also reflected in the Authority’s “marginal benefit adjustment mechanism”. However, this mechanism had major workability issues and is unlikely to be able to be successfully implemented.

The Authority went on to suggest “the position is different for forward-looking grid investment decisions” but failed to recognise once the forward-looking grid investments are made they will then become sunk and the above set of concerns would arise. (Further, if a direct connect customer

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<sup>38</sup> Electricity Authority, Review of distributed generation pricing principles, Decisions and reasons, 6 December 2016, paragraph C.108(a).

expects a transmission investment to occur in the future they would rationally consider the potential implications of distributed generation on their future AoB charges.)

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### 6.3.3 ALIGNING TPM AND DGPP

One thing the Authority could do, if AoB is adopted, is to amend Schedule 6.4 to define ACOT as avoided LRMC charges only i.e. no ACOT for avoidance of AoB or residual charges.

This would have the added attraction of removing the current mess in Schedule 6.4 with the mixing of “avoided” and “avoidable cost” concepts, and potential questions about what transmission costs “an efficient distributor would be able to avoid”.

The example above illustrates why this may only mask underlying problems with AoB.

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## APPENDIX A: GUIDELINES REVIEW

Please refer attached Appendix A



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## **APPENDIX B: ECONOMIC REPORT AXIOM CONSULTING**

Please refer attached Appendix B

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## APPENDIX C: ELECTRICITY AUTHORITY LRMC WORKING PAPER

We consider the Authority's previous LRMC Working Paper assessment of LRMC was orthodox and fundamentally sound. However, the paper overstated the practical problems with applying LRMC relative to beneficiaries-pay options.

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### THE MERITS OF LRMC PRICING

We agree with the Authority's, then, position that LRMC is superior to other pricing options:

- "... charges based on LRMC could promote dynamic efficiency"<sup>39</sup>
- "LRMC is forward looking ..." <sup>40</sup>
- "charges based on the LRMC of transmission would provide efficient price signals about the cost of transmission investment"<sup>41</sup>
- "Peak period prices equal LRMC in workably competitive markets ..." <sup>42</sup>
- "LRMC charges are market-like and are therefore, in principle, more preferred under the Authority's decision-making and economic framework". <sup>43</sup>

These positions are entirely consistent with the views the Authority expressed in the 1<sup>st</sup> Issues Paper and in relation to distribution pricing. For example, the Authority noted that, in areas such as UNI and USI, where "The need for interconnection investment ... is ... largely driven by regional peak demand growth"<sup>44</sup> it is efficient to apply a peak-usage charge, such as RCPD, as long as the level of the RCPD charge doesn't rise substantially, as a result of additional transmission investment, such that "the level of response to RCPD could increase past the efficient level and cause a net economic cost".<sup>45</sup> Capping any peak-usage charge at LRMC, with any revenue shortfall recovered through a residual charge, would achieve this.

We agree beneficiaries-pay options should be seen as 2<sup>nd</sup>-best. As the Authority has noted "Beneficiaries-pay charges do not reflect LRMC. A beneficiaries-pay charge would therefore be less successful than a theoretically efficient LRMC charge at promoting efficient investment"<sup>46</sup>). We also agree that beneficiaries-pay should be considered if LRMC is not practicable ("... the Authority considered that, in the absence of a mechanism that produces prices that reflect LRMC, benefit-based charges are likely to be the most efficient means of promoting dynamic efficiency"<sup>47</sup>).

We also agree with the Authority that nodal pricing sends statically efficient (SRMC) pricing signals which fall short of LRMC.

We consider the positions outlined in the LRMC Working Paper are not consistent with the position the Authority has adopted with its beneficiaries-pay (AoB) approach (the principal component of its TPM proposal) and LRMC, even if the LRMC is determined to be practical. The LRMC should not be

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<sup>39</sup> Electricity Authority, Working Paper, TPM Review: LRMC charges, 29 July 2014, paragraph 4.1.

<sup>40</sup> Ditto paragraph 1.6.

<sup>41</sup> Ditto paragraph 1.4.

<sup>42</sup> Ditto paragraph 1.6.

<sup>43</sup> Ditto paragraph 1.6.

<sup>44</sup> Electricity Authority, Transmission Pricing Methodology: issues and proposal, 10 October 2012, Appendix D, paragraphs 64 and 79.

<sup>45</sup> Ditto paragraph 78.

<sup>46</sup> Electricity Authority, Working Paper, TPM Review: LRMC charges, 29 July 2014, paragraph 5.20 [emphasis added].

<sup>47</sup> Ditto paragraph 4.3.

subjugated to a discretionary (“additional”) component of the TPM but should be a mandatory component.

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## NODAL PRICING

We agreed with the previous position that nodal pricing sends statically efficient (SRMC) pricing signals which fall short of LRMC.

Despite the fact the LRMC Working Paper detailed, uncontroversially, why nodal pricing only sends efficient SRMC pricing signals, and falls well short of sending dynamically-efficient LRMC price signals for investment,<sup>48</sup> the 2<sup>nd</sup> Issues Paper ignored this and treated the adequacy of nodal pricing signals “in regard to the timing of future transmission investment”<sup>49</sup> as an open question. The 2<sup>nd</sup> Issues Paper concluded, as a consequence, “in proposing an LRMC charge to supplement nodal prices, Transpower would have to demonstrate to the Authority that a price signal over and above the price signal provided by nodal pricing and other transmission charges is necessary to promote efficient investment in, and use of, the interconnected grid”.<sup>50</sup> The Supplementary Consultation, similarly, includes statements that “an LRMC charge is most likely to be needed to ration use of the *existing* grid to efficiently defer new investment when, for some reason, nodal prices are not sufficient to do so ...”<sup>51</sup> [emphasis added]. In our view the LRMC Working Paper has already addressed these questions, and detailed what the “some reason” is.<sup>52</sup>

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## ANALYSIS OF THE LRMC WORKING PAPER WITH OUR COMMENT

The table below presents Authority view on aspects of the LRMC and our comment to each.

Electricity Authority position	Comment
“... charges based on LRMC could promote dynamic efficiency” <sup>53</sup>	Agreed. This reflects an orthodox position on LRMC pricing.
“LRMC is forward looking, as it is the cost of future changes in capacity of the grid to meet future changes in demand. LRMC charges are market-like and are therefore, in principle, more preferred under the Authority’s decision-making and economic framework. Peak period prices equal LRMC in workably competitive markets where fixed costs are somewhat large, thus promoting efficient investment. Thus, market-like prices in the TPM would involve setting prices for peak demand periods equal to LRMC.” <sup>54</sup>	Agreed.  Consistent with view in the 2 <sup>nd</sup> Issues Paper that: “The LRMC charge is a market-like charge that would restrict use of the interconnected grid when that is efficient. In particular, the Authority considers that an LRMC charge could provide an efficient price signal in advance of a major new grid investment programme”. <sup>55</sup>
“Pricing in workably competitive markets produces prices broadly reflective of SRMC and LRMC”	Agreed. This reflects an orthodox position on marginal cost pricing.

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<sup>48</sup> Electricity Authority, Working Paper, TPM Review: LRMC charges, 29 July 2014, paragraph 8.11 onwards. The 2<sup>nd</sup> Issues Paper also addressed this point: refer to Electricity Authority TPM Second issues paper, 17 May 2016, paragraph 124.

<sup>49</sup> Electricity Authority, TPM Second issues paper 17 May 2016, paragraph 124.

<sup>50</sup> Ditto paragraph 125.

<sup>51</sup> Electricity Authority, TPM Second issues paper, Supplementary consultation, 13 December 2016, paragraph 3.151.

<sup>52</sup> And a wide range of submissions, in response to the 2<sup>nd</sup> Issues Paper, addressed this point in terms of “other transmission charges”; specifically, the AoB charges and the Authority’s “shadow pricing” theory.

<sup>53</sup> Electricity Authority, Working Paper, TPM Review: LRMC charges, 29 July 2014, paragraph 4.1.

<sup>54</sup> Ditto paragraph 1.6.

<sup>55</sup> Electricity Authority, TPM Second issues paper 17 May 2016, paragraph 124.

Electricity Authority position	Comment
"If grid services were priced as in workably competitive markets, prices would reflect SRMC during off-peak periods and LRMC during peaks" <sup>56</sup>	
"... nodal prices are likely to under-signal LRMC so LRMC charges could potentially promote more efficient investment." <sup>57</sup>	Agreed.  The LRMC Working Paper clearly spelt out the reasons why nodal pricing does not provide (dynamically-efficient) adequate investment pricing signals, yet the 2 <sup>nd</sup> Issues Paper treats this as an open question: "Whether such a [LRMC] charge would be beneficial depends, in part, on whether nodal spot prices provide an efficient signal in regard to the timing of future transmission investment". <sup>58</sup>
"... the Authority is considering LRMC charges as they are a market-like charge rather than because an externality has been identified, which would require exacerbators-pay charging to be considered." <sup>59</sup>	LRMC is consistent with market-like and exacerbator pays. The DM&F makes no reference to exacerbator-pays requiring the existence of externalities.
"In principle, the Authority agrees that an efficient LRMC charge is likely to be more efficient than a beneficiaries-pay charge." <sup>60</sup>	Agreed. This is consistent with the specification of the DM&E framework. As the Authority has noted:  "Submitters considered that: (a) LRMC charges were more preferred under the Authority's decision-making and economic framework for the TPM and would better promote the Authority's statutory objective than other options the Authority had favoured such as beneficiaries-pay charges". <sup>61</sup>
"The Authority has been considering beneficiaries-pay charges because of their potential to promote more efficient investment. LRMC charges are potentially a more efficient alternative for achieving this objective." <sup>62</sup>	
"... the Authority considered that, in the absence of a mechanism that produces prices that reflect LRMC, benefit-based charges are likely to be the most efficient means of promoting dynamic efficiency." <sup>63</sup>  "Beneficiaries-pay pricing would be next preferred if LRMC charging is impracticable" <sup>64</sup>	
"The [beneficiaries-pay] working paper acknowledged that setting prices according to incremental benefit at best only	Agreed. This is inconsistent with the approach Oakley Greenwood applied in the CBA.

<sup>56</sup> Electricity Authority, Working Paper, TPM Review: LRMC charges, 29 July 2014, page 14.

<sup>57</sup> Ditto, paragraph 8.12.

<sup>58</sup> Electricity Authority, TPM Second issues paper 17 May 2016, paragraph 124.

<sup>59</sup> Electricity Authority, Working Paper TPM Review: LRMC charges, 29 July 2014, page 11, Table 1.

<sup>60</sup> Ditto Table 1.

<sup>61</sup> Ditto paragraph 1.5(a).

<sup>62</sup> Ditto page 10, Table 1.

<sup>63</sup> Ditto paragraph 4.3.

<sup>64</sup> Ditto page 16.

Electricity Authority position	Comment
<p>approximates efficient signals since prices are unlikely to reflect LRM. ”<sup>65</sup></p> <p>“Beneficiaries-pay charges do not reflect LRM. A beneficiaries-pay charge would therefore be less successful than a theoretically efficient LRM charge at promoting efficient investment.”<sup>66</sup></p>	
<p>“LRM charges ... have been applied in the United Kingdom (UK) except Northern Ireland ... However, unlike New Zealand, the UK does not have nodal pricing in their wholesale electricity markets (which provides price signals that reflect at least the short-run marginal cost (SRM) of transmission). Nevertheless, the UK experience is relevant as the rationale for their LRM charges is promotion of efficient investment.”<sup>67</sup></p>	<p>Agreed. The impact of nodal pricing (reflecting SRM) can be taken into account when setting LRM charges, as reflected in the Authority’s proposed Guidelines.</p>
<p>“Submitters considered that ... Practical methods of applying LRM charges had been identified earlier in the review, such as the tilted postage stamp, and LRM charges could also be readily applied by other means such as modifications to the status quo and the Authority’s zonal SPD charge proposal. The Commerce Commission’s application of total service long-run incremental cost (TSLRIC) charges to telecommunications may provide insights to the application of LRM charges” .<sup>68</sup></p>	<p>Agreed. There are a range of methods that could be adopted. The four region LRM pricing methodology Oakley Greenwood modelled is probably one of the simpler LRM options that could be adopted/which would result in the smallest changes from the status quo.</p>
Practical issues with LRM	
<p>“The beneficiaries-pay working paper ... suggested that the 'loop flow' characteristics of the interconnected grid, combined with the large number of parties using the grid, made it impracticable to apply LRM charges. The Authority therefore considered that a beneficiaries-pay approach is the next best option in terms of efficiency and practicality” .<sup>69</sup></p>	<p>The Authority noted “Submitters considered that ... The reasons that the Authority had advanced for not investigating LRM charges further were not valid as the SPD charge indicated practical difficulties such as dealing with loop flows and large number of grid users under LRM could be readily overcome” .<sup>70</sup></p> <p>The Authority, itself, recognised “Methods are available that mean loop flows do not prevent calculation of LRM charges” .<sup>71</sup></p>
<p>“There are a number of practicability issues that would need to be addressed before applying an LRM charge. On a technical level these include:</p>	<p>These “practicability issues” are straightforward to overcome relative to the challenges with applying the AoB methodology. As the Authority has noted,</p>

<sup>65</sup> Electricity Authority, Working Paper, TPM Review: LRM charges, 29 July 2014 paragraph 4.3.

<sup>66</sup> Ditto paragraph 5.20.

<sup>67</sup> Ditto 7.10.

<sup>68</sup> Ditto, paragraph 1.5(c).

<sup>69</sup> Ditto paragraph 1.4.

<sup>70</sup> Ditto paragraph 1.5(b).

<sup>71</sup> Ditto 29 July 2014 page 29.

Electricity Authority position	Comment
<p>(a) the definition of LRMC to be used</p> <p>(b) the methodology used for calculating LRMC – MIC, AIC, LRIC or another methodology</p> <p>(c) the appropriate approach for forecasting demand for transmission services to be used for calculating LRMC ...”<sup>72</sup></p>	<p>LRMC has been implemented in other jurisdictions. Matters such as “forecasting demand” is a standard part of price determination under Part 4 Commerce Act.</p>
<p>“LRMC charges provide price signals based on investments that are expected to occur in the (distant) future. The LRMC charges for each investment reduce to zero when the new asset is commissioned. Once a party is charged for future investments they would appear to have perverse incentives to push for those investments to occur as soon as possible so as to reduce their charges to a minimum”.<sup>73</sup></p>	<p>This comment assumes a particular form of LRMC, which is applied on a granular investment by investment basis.</p> <p>The concern the Authority raises is straightforward to address.</p> <p>It is dealt with under both Transpower’s Simplified Staged Alternative, and the Authority’s proposed AoB TPM, by allocating new investment using a form of AoB.</p>
<p>“An LRMC charging regime may be unsustainable as parties would be paying for assets/services that don’t yet exist ...”<sup>74</sup></p>	<p>This statement is slightly misleading. The Commerce Commission sets the amount parties pay (overall) is based on the current and forecast costs of providing transmission services over the 5-year regulatory period.</p>
<p>“There is also the issue of whether the regulator can reasonably assess the accuracy of the forecasts of demand and transmission investments. Those forecasts are likely to change over time, and new investment and technology options will arise over time. These issues lead the Authority to question whether the charging regime will be sufficiently robust over time to be sustainable.”<sup>75</sup></p>	<p>These are issues the Commerce Commission needs to address when it sets its price determinations under Part 4 Commerce Act. As the Authority noted “Regarding forecasting demand, the demand forecasts used to determine Transpower’s individual price-quality path (IPP) under Part 4 of the Commerce Act could be used”.<sup>76</sup></p> <p>The types of assessments required for LRMC pricing would be straightforward relative to the requirements for applying the Authority’s proposed AoB methodology.</p>
<p>“More fundamentally, an LRMC charging regime may be unsustainable as parties would be paying charges based on assets/services that don’t yet exist. The charges are likely to be viewed by payers as critically dependent on questionable assumptions and forecasts, and ongoing revisions to those assumptions and forecasts would likely make it clear that the</p>	<p>These issues would be far more severe under AoB.</p> <p>If issues about the charges being based on “questionable assumptions and forecasts”, and that “setting of the</p>

<sup>72</sup> Electricity Authority, Working Paper, TPM Review: LRMC charges, 29 July 2014 paragraph 1.4.

<sup>73</sup> Ditto paragraph 1.18(a).

<sup>74</sup> Ditto paragraph 1.18(b).

<sup>75</sup> Ditto paragraph 1.18(b).

<sup>76</sup> Ditto paragraph 8.3.

Electricity Authority position	Comment
<p>setting of the charge is highly subjective. These issues lead the Authority to question whether the charging regime would be sufficiently robust over time to be sustainable.”<sup>77</sup></p> <p>“The Authority notes that these practicability issues are considerable and, to the extent they can be resolved, significant time would be required.”<sup>78</sup></p>	<p>charge is highly subjective” is sufficient grounds to reject LRMC, then the Authority’s AoB charge proposals would also need to be rejected.</p>
<p>“if [sic] LRMC charges were applied but did not fully recover Transpower’s, costs the Authority’s decision-making and economic framework implies a beneficiaries-pay charge should be applied to recover remaining costs. The combination of LRMC and beneficiaries-pay charges, and possibly residual charges, would be more complex than the status quo.”<sup>79</sup></p>	<p>The combination of beneficiaries-pay and residual charges under the Authority’s proposals would also be more complex than the status quo.</p>
<p>“A quantified CBA would be required to determine whether LRMC charges would provide net benefits relative to the status quo. The Authority’s preliminary assessment is that LRMC charges could provide net benefits relative to the status quo. A final assessment would depend on whether the potential efficiency improvements resulting from LRMC charges would occur in practice under a regulated regime, and if so, whether they would outweigh the significant implementation, operational and other costs of applying those charges.”<sup>80</sup></p>	<p>The Oakley Greenwood CBA determined that a simplified 4-region LRMC methodology would provide (modest) net benefits relative to the status quo.</p> <p>The “implementation, operational and other costs of applying [LRMC] charges” would be smaller than that for the 2<sup>nd</sup> Options Paper AoB charges.</p>
<p>“LRMC charging involves estimates of LRMC based on current technology but relates to future investment costs. This means there would be a risk that if the investment is actually made: (a) the technology used for that investment may be different from that on which the LRMC calculation is based ...</p> <p>“The main risk with (a) would be that technological change raises a risk of a mismatch between LRMC charges and the actual costs of the investment. Since technological change would probably be more likely to reduce rather than increase costs, LRMC charges may be higher than would be efficient. The consequence of an excessive LRMC charge would be lower demand for transmission services than is efficient and inefficient deferment of investments.</p> <p>“While this risk is a real one, the key question is whether the efficiency consequences of this are worse than the alternatives. For example, the charges under the status quo and beneficiaries-pay charges are based on the actual costs of investments that have been incurred, ie historical costs. This means that to the extent there is a risk of over-charging with LRMC charges it may actually be worse for the status quo and beneficiaries-pay.”<sup>81</sup></p>	<p>The peak-usage signal would be zero if an LRMC charge is not adopted.</p> <p>An imperfect peak-usage signal will be more accurate and more efficient than a zero peak-usage signal.</p> <p>With respect, we consider that the commentary that AoB charges are based on historic costs and therefore more accurate than LRMC compares apples and oranges and is spurious.</p> <p>The estimation of LRMC, based on future investment-costs, will be more straightforward, and less prone to error, than estimating the private benefits consumers will receive over the lifetime of AoB assets.</p>

<sup>77</sup> Electricity Authority, Working Paper, TPM Review: LRMC charges, 29 July 2014 paragraph 8.37.

<sup>78</sup> Ditto paragraph 1.19.

<sup>79</sup> Ditto paragraph 1.20.

<sup>80</sup> Ditto paragraph 1.23.

<sup>81</sup> Electricity Authority, Working Paper, TPM Review: LRMC charges, 29 July 2014, paragraphs 8.32-8.34.

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## APPENDIX D: COMMENT ON CONCEPT CONSULTING WINTER CAPACITY REPORT

An important component of ensuring the EA decisions on TPM and DGPP are evidence-based and robust, and for understanding the risks associated with those decisions, is testing the impact of removing RCPD peak-usage charges.

For our submission the second issues paper, and using with information provided via the EA and EDBs, we undertook a high level analysis of:

- i. The location, capacity, type and operation of **installed DG plant** including coincidence with RCPD
- ii. The approximate location, capacity, type and operation of **demand management** including coincidence with RCPD

This analysis established, with a reasonable level of confidence, system, island and regional 'gross demand' i.e. observed RCPD + DG + demand management. The analysis indicated that 20% of system peak gross demand was met by demand response and DG (over 30% in some areas), and the grid could not currently meet gross demand in all areas.

After submissions Concept Consulting undertook analysis of changes to the TPM and DGPPs for their impact on the Winter Capacity Margin (WCM). The purpose of Concept Report is to test the risk that the proposed changes to the TPM and DGPPs result in extreme and or inefficient shifts in demand and / or supply that could cause security of supply problems (and / or inefficient transmission investment).

During the report process we met with Concept to provide feedback on a draft (unpublished), report. We have reviewed the published report for any changes to its approach following our feedback. Our conclusion is that Concept approach was little changed by our feedback. If anything the approach became more bullish by the additional inclusion of all 'medium probability' generation<sup>[1]</sup>

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### CHANGES IN PUBLISHED CONCEPT REPORT

We have reviewed the final version of the Concept report. Between the draft report and the final report, we understand the main changes were:

- Change the assessment period to 2019 (from 2018);
- Increase the estimated loss of EDB load management from 35MW (net) to 50MW (net). The gross loss is expected to be 170MW of which 120 MW is assumed to be used in the IR market (so a 50MW loss overall);
- Include 'medium probability investment' within the WCM
- Base case conclusion is the same (that WCM it is within the economic range)
- Both sensitivity 1 and 2 scenarios mean WCM is not met.

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<sup>[1]</sup> This is a measure used by the System Operator in its Annual Security of Supply Assessment.



We recognise the views in the report are those of Concept and not the Authority. We appreciate the consideration by Concept of Transpower's feedback on its draft report.

As we understand it, no substantive changes have been made in response to our feedback.

We include for completeness and transparency the feedback we provided on the draft report, the main thrust of which is relevant to Concept's final report.

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## WINTER CAPACITY MARGIN ASSESSMENT – TRANSPOWER'S INITIAL COMMENT ON CONCEPT REPORT

### Introduction

The EA asked Transpower to review a confidential draft report by Concept Consulting into the potential impact on winter capacity margins of proceeding with its May 2016 TPM and DGPP proposals<sup>82</sup>, in particular:

- Removing the regional coincident peak demand (RCPD) charge to which demand management by EDBs and industrials responds
- Removing the distributed generation pricing principles under which EDBs pay DG for avoided network costs (typically mirroring avoided RCPD charges).

This note contains our high-level initial thoughts on Concept's work:

1. Context for the purpose of the Concept Report and why the work is so important
2. Key observations on, including limitations of, Concept's analysis
3. Initial ideas on the need for further work.

Although Transpower has raised concerns with the EA about its TPM and DGPP proposals we are committed to assisting the EA reach robust decisions on both reviews and maintain a regular working level dialogue on both topics.

### Summary of initial views

- An important component of ensuring the EA decisions on TPM and DGPP are evidence-based and robust, and for understanding the risks associated with those decisions, is testing the impact of removing RCPD peak-usage charges, in the event EA's "shadow pricing" logic does not hold. Subject to the comments in this note, we consider the Concept work assist could with that objective.
- As we understand it, the purpose of Concept Report is to test the risk that the proposed changes to the TPM and DGPPs result in extreme and or inefficient shifts in demand and / or supply that could cause security of supply problems (and / or inefficient transmission investment).

We see the risks as most acute in the period of transition from status quo DGPP and TPM to a, new, untested regime (after which a general equilibrium analysis may be the best methodology for testing long-run effects<sup>83</sup>) and consider further work is required here.

- To achieve the purpose above, the analysis would ideally model high risk and potential worst case scenarios, and not be limited to sensitivities around what appears a best case (most benign)

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<sup>82</sup> This follows the briefing we provided Concept on this matter (26 August), and our offer to review Concept's work in due course.

<sup>83</sup> Although, if investor expectations are not respected in the transition, future investment may be chilled requiring adjustment of model parameters.

scenario. For example: combining sensitivity cases 1 and 2 which appear plausible, especially during transition from the current TPM and DGPPs to a different regime.

- Similarly, care should be taken not to simply assume risks away. For example, Transpower and others have raised concerns with the efficacy of the 'shadow price' provided by the AoB, but Concept appears to accept without question that the Authority's view that the shadow price logic holds (which presumably influenced its base case selection).
- While it is understandable that the Concept Report is heavily qualified and necessarily makes a number of simplifying assumptions<sup>84</sup>, these assumptions and qualifications do limit the evidential value of this analysis and the extent to which its conclusions could be relied upon at this point.
- A more sophisticated and granular approach than the current macro (island level) analysis would also help identify transmission constraints and regional hot spots that could impact the headline results. We recognise this is not a straightforward analysis.
- In summary, the Concept Report is a potentially useful input into the TPM and DGPP review processes, but requires expansion and development before it could be relied upon to underpin major policy decisions.

## 1. Context

One of the judgements the EA has made, in support of the proposed removal of RCPD or any form of explicit peak-usage charge, is that a combination of (short-run) nodal prices and a "shadow price" provided by AoB, would provide dynamically-efficient pricing signals.

This view has proven contentious and we do not believe the Authority is correct. Submitters' responses to the May 2016 DGPP and TPM consultations, including Transpower, identified the potential risks of removing long established and understood ex ante price signals.

Consequently, whether LRMC-type peak-usage charges are needed in the TPM has been a topic of ongoing debate between the EA and Transpower.

As part of a preliminary assessment of the risks of removing RCPD pricing signals (under both the TPM and ACOT), Transpower, with information provided via the EA and EDBs, undertook a high level analysis of:

- iii. The location, capacity, type and operation of **installed DG plant** including coincidence with RCPD
- iv. The approximate location, capacity, type and operation of **demand management** including coincidence with RCPD

This analysis established, with a reasonable level of confidence, system, island and regional 'gross demand' i.e. observed RCPD + DG + demand management. The analysis indicated that 20% of system peak gross demand was met by demand response and DG (over 30% in some areas), and the grid could not currently meet gross demand in all areas.

Transpower also:

- Undertook limited high level, preliminary analysis of potential security of supply issues in three regions (LSI, USI, UNI), summaries of which were included in our submission
- Initiated, but did not complete, scoping work on a larger and more sophisticated system wide analysis of the potential implications of the EA's proposal.

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<sup>84</sup> For example, analysing a base year that it likely to be 3 years before the new TPM takes effect and before the scheduled closure of key generation plant.

## 2. Initial Comment on report

We are pleased that the EA is looking to understand and quantify the impact of the TPM/DGPP proposals on peak grid load.

This should help the EA arrive at robust decisions, and, avoid unintended consequences – including the otherwise plausible combination of (i) system security problems (ii) higher than efficient energy costs (iii) early or unnecessary transmission investment, and (iv) impediments to retail competition.

Although we have not been able to undertake a thorough review of Concept's work in the time available we can provide the following general comments at this point:

- **Efficacy of shadow pricing:** As previously indicated, we do not share the Authority's (or Concept's) belief that the shadow AoB price will provide efficient forward looking price signals. This is significant when considering how future price signals from the TPM will affect behaviour.

In the context of the work that Concept was commissioned by the EA to undertake, the theoretical merit of shadow pricing under AoB isn't so important. What is important is building up an evidence-based assessment of the risks that would arise if the EA turns out to be wrong. For example, what happens if the shadow price logic does not hold, and or agency (or other problems) means price signals are not received by parties capable of responding?

- **Caveats:** We note the extent to which Concept has chosen to caveat their analysis, given the number of assumptions it has been necessary for Concept to make in undertaking the analysis, not the least of which is the uncertainty of participant response. Such qualifications are not surprising as they represent, in essence, the crux of the concerns raised by submitters about the removal of explicit ex ante price signals.

It is apparent that Concept was reluctant to analyse years beyond 2018 because of a greater range of uncertainties unrelated to the TPM/DGPP proposals – such as underlying demand growth, decisions about commissioning and decommissioning of generation etc. This reluctance is understandable but it does limit the evidential value of the analysis and the extent to which the analysis can be relied upon.

- **Sensitivities:** The report acknowledges the uncertainties in the assessment and considers two sensitivity cases in regards to DG non-response and DR non-response. However, these scenarios are:
  - i. Considered independently of each other
  - ii. Both considered less likely than the base case, the effect of which is to reduce DG and DR non-response (although we note the report does recognise some combinations of the sensitivity cases is possible).

We consider that, given the stated uncertainties in the participant response and underlying modelling assumptions (with some potential effects as highlighted in the above points) more extreme combinations of DR and DG non-response could potentially occur where combinations of DR and DR non-response intersect at varying degrees.

This is particularly plausible in the short-term during transition from one regime to another (when a combination of agency problems and strategic behaviour could result in an outcome more akin to the two sensitivities occurring concurrently).

We note that a long-run equilibrium assessment will tend to mute some of the extreme combinations that could exist during the day-to-day operation or could become visible in a probabilistic impact assessment (which was preferred but out-of-scope - see section 2.4). Scenarios that cover off some less likely but plausible outcomes could highlight potential lower probability but higher impact risks. For example, the combined sensitivity 1 and 2 where demand increases by ~850MW, or more extreme scenarios.

- **Scenario bounds:** While the three projections may be reflective of potential outcomes, the basis on which the base case projection is considered more likely is unclear. We do not consider the sensitivities should be seen as bounds on potential outcomes and, as noted above, consider a worse-case scenario is certainly plausible (and is potentially likely during the transition period).
- **Regional view:** The analysis to date, including the Concept work, continues to consider the issue from an island or national perspective and conclude that adequate incentive may exist to deliver the desired outcome on the basis of gross numbers and assumed behaviours.

We recognise Concept's methodology is based on our own security of supply methods but query whether this should be revisited with the removal of peak price signals and dilution of incentives for load management and DG.

- **Transaction costs and information asymmetry:** An almost entirely new transmission pricing and ACOT framework is contemplated. In addition to potential for policy error (as discussed above in relation to shadow pricing) there is significant potential for transaction costs, information asymmetry and agency problems to weaken (or invalidate) assumed incentives and corresponding behaviours; especially during the establishment and transition stages.

For example, Concept note that *"to assess the prospective AoB signal, participants would need to understand the likelihood and timing of grid investment, the resulting AoB charge impact for them, and options to defer investment. The processes and information to support this are likely to require development, relative to current arrangements"*.

We agree with this view (we and others made similar points in submissions). However, we note many potential participants are relatively small entities who are unlikely to have the existing capability to analyse this information. This will require either they build capability or someone else does this for them (or possibly that they simply don't respond).

- **Risk appetite:** A general theme of the comments above and our impression of Concept's approach is that it has a somewhat higher risk appetite than Transpower would apply in either our capacity as grid planner or system operator.

We consider it has made a series of compounding assumptions and judgements that combine to create:

- i. an unduly optimistic base case; and
- ii. overly optimistic worst case scenarios.

That said, we appreciate this is a difficult analysis to perform and do not wish to be critical of Concept's report.

### 3. Further work required

We appreciate the constraints Concept has had to work to in order to produce the draft report in such a short-time. We faced similar constraints when undertaking similar analysis during the May-July consultation period.

The draft report contains a lot of useful information which Concept can build upon.

What we would like to see is modelling over different (short to longer) time-periods, projected from the point at which the new TPM is expected to take effect. Modelling a period when the existing TPM would still be in place is of limited value.

We would also like to see the report move away from its emphasis on what Concept sees as a most likely "base case" and test a broader range of scenarios including where the shadow pricing logic does not hold.

While the report does indicate that regional effects are out of scope, we note that there may be some within-island effects that are not captured within an island-based assessment, and this would be worth exploring.

To the extent Concept is then able to advise on the extent or probability of potential adverse scenarios it would serve to inform the TPM review about the materiality of risks from full removal of RCPD or any other form of explicit peak-usage charge.

#### **4. Next steps**

This response is a summary and we would be happy to discuss the thinking that underpins the points outlined above (but, in the interests of timeliness, did not wish to delay the response to fully articulate that detailed thinking) and more specific comments.

For example, in the executive summary, the paper makes reference to “new plant investment characterised as ‘high probability’ by Transpower”. This characterisation is the result of industry submissions and a defined methodology and doesn’t represent a Transpower view. If possible, we suggest an alternate reference, perhaps to the Annual Security of Supply Assessment itself or to the source of the information.

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## **APPENDIX E: TRANSPower SUBMISSION TO ENA REVIEW OF DISTRIBUTION PRICING OPTIONS**

Please refer attached Appendix E

