Meridian Energy Submission

Transmission Pricing Methodology: Second issues paper – Supplementary 'Refinements' Consultation

24 February 2017

INTRODUCTION

This submission by Meridian Energy Limited (**Meridian**) responds to the Electricity Authority's consultation paper *Transmission Pricing Methodology: Second issues paper: Supplementary consultation* document (**Refinements Paper**) dated 13 December 2016.

Meridian's submission comprises this report and appendix, and three accompanying expert reports:

- NERA Economic Consulting *Transmission pricing methodology – review of supplementary paper* (24 February 2017) (**NERA Report**);
- Professor Stephen Littlechild *Report on the Electricity Authority's Supplementary Consultation Paper* (19 February 2017) (**Littlechild Report**); and
- Adjunct Professor E. Grant Read *New Zealand TPM Refinement – Some comments on the Electricity Authority's December 2016 Guidelines Draft* (24 February 2017) (**Read Report**).

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EXECUTIVE SUMMARY

Overall proposal

Meridian continues to support the Authority's proposals. It considers the Authority's definition of the problems with the status quo is accurate, and that the core proposals will address the present imbalances in charges for the HVDC assets and recent major investments, and improve decision-making for future transmission and other investments.

Meridian supports most of the refinements in the Refinements Paper. However, it opposes:

- the proposed expanded scope of the Area of Benefit (**AoB**) charge (refinement #1); and
- the proposal for revaluing historic assets without taking into account depreciation that has been funded to date (refinement #4).

Refinement #1: Expansion of the AoB charge

Meridian considers that only the recent major investments (and Pole 2) that comprise the "eligible investments" (as defined in the Second Issues Paper) should be subject to the AoB charge. This approach will remove the present inefficiencies and concerns about durability created by the mismatch between who benefits from those assets and who pays for recent capital expenditure and the HVDC assets, while striking a pragmatic balance of AoB coverage versus practicability.

Furthermore, Meridian considers that expanding the AoB charge beyond the "eligible investments" will not improve the efficiency of the new TPM and will be highly contentious in terms of the historical costs of such assets, the appropriate approach to depreciation and the allocation of benefits. Meridian is very concerned that, in respect of the tail of historic assets, the AoB charge will operate as a series of separately allocated "pseudo residual" charges (based on proxy asset costs and without attempting to determine expected benefits), unconstrained by the Authority's findings and proposed rules for the actual residual charge, namely that it should be broadly based and applied only to load.

In Meridian's view, refinement #1 would weaken the efficiency and durability of the new TPM, and should be discarded.

Refinement #4: Revaluation of historic assets

Meridian strongly opposes the proposal that the annual AoB charges to be recovered in respect of historic assets will be determined as if an indexed historic cost (**IHC**) valuation had applied since the asset was commissioned, and without taking into account depreciation that has been funded to date. Such an approach amounts to a revaluation of these assets. TPM charges to date have been set on the basis of a depreciated historic cost (**DHC**) approach which means that charges are higher in earlier years and lower in later years than under an IHC approach. Switching methodologies part way through the asset life's will result in excessive returns and will not be cost-reflective.[1] Similar approaches have been considered and rejected by the Commerce Commission and the Courts.

The Authority's argument that workably competitive markets necessarily produce such charges is not supported by theory or practice, and its preference for such an approach cannot outweigh the undermining of cost-reflectivity that will occur. Meridian estimates that total overpayment in relation to Pole 2 and Pole 3 alone could be in the order of $400m over their remaining lifetimes. The Authority was right in the Second Issues Paper to say that such an outcome would "seriously [breach] the principle of cost-reflectiveness".[2] A "solution" to the present HVDC problem that ignores depreciation funded by past HVDC charges and leads to over-recovery would be irrational and would risk undermining the durability of a new TPM. Refinement #4 "is inconsistent with the methodology set out in the Second Issues paper, insofar as the total price to be paid over time for certain important assets will no longer equal the cost of providing them, and this will undermine the principles underlying the reformed approach."[3]

Rather, the Authority's objective of a flat cost recovery could be achieved by turning the unrecovered present value of the asset into an annuity as reflected in the RAB.

Form and content of the draft guidelines

In Meridian's view, in order to avoid extended future debates about their meaning, the guidelines should be drafted so they could be understood by someone who has not been involved in the process to date. For example, clear statements should be made as to the intention of the TPM as a whole and of each individual charge. In addition, for matters where the Authority is the appropriate decision-maker, principles should be determined now and not left for further consultation by Transpower.

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1 NERA Report at [8] and section 3.2.

2 Electricity Authority *Transmission Pricing Methodology: Issues and proposal second issues paper* (17 May 2016) [Second Issues Paper] at [7.161].

3 Littlechild Report at [22].

It is important that the proposals retain a demarcation between the roles of the Authority and Transpower. This can sensibly be done by considering whether Transpower or the Authority has better information and expertise, appropriate incentives, and any disqualifying interests. The Authority is tasked with oversight of the electricity industry and has particular economic expertise; Transpower does not; the Authority has a strong incentive to pursue its statutory objective whereas Transpower is indifferent to how its revenue is collected; and Transpower has opposed some of the Authority's proposals and is likely to have firm views on critical aspects of the proposed refinements. On that basis the refinements generally give too much discretion to Transpower.

Cost-benefit analysis (CBA)

Meridian endorses NERA's analysis that the responses by Oakley Greenwood (**OGW**) and the Authority to issues raised about the CBA and OGW's assessment of the impact of the proposed refinements on its CBA are generally reasonable and correct.[4] Meridian also supports NERA's endorsement of the Authority's CBA as informative and appropriate.[5]

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4 NERA Report at section 5.1.

5 NERA Report at section 5.2.

THE 18 REFINEMENTS

1. Allowing for a broader coverage of the AoB charge and a transition as an additional component

Introduction

1. The Authority has proposed that, in addition to the “eligible investments” specified in the Second Issues Paper, Transpower must, if doing so would be practicable and consistent with clause 12.89, include in the TPM as an additional component a method for extending the AoB charge to include other pre-guidelines assets.

2. Meridian opposes this proposed refinement. The Authority, rather than Transpower, should be responsible for determining the scope of the AoB charge. The definition of eligible investments proposed in the Second Issues Paper is entirely appropriate and the AoB charge should not be extended to include other pre-guidelines assets.

Background

3. In the Second Issues Paper the Authority defined eligible assets as existing investments approved after May 2004 having a value of more than $50 million at the time of commissioning, and Pole 2.[6] The Authority recognised that the TPM would be more durable if the AoB charge applied to recent major investments (that is, by correcting the imbalance in the present TPM).[7] The rationale for the particular cut off point was that:[8]

   (i) “[T]he efficiency gains from charging for historical assets (through improvements to durability and therefore investment efficiency) need to be traded-off against the additional costs of applying the area-of-benefit charge to historical assets.”

   (ii) “The $50 million threshold would limit the application of the charge to assets within a relatively small number of investments, which would reduce implementation costs compared with applying the charge to, for example, all historical assets approved since May 2004.”

   (iii) “However, the $50 million threshold still captures the bulk of the total value of existing assets that have been approved since May 2004, effectively addressing the durability issue.”

4. The set of existing investments that would be subject to the AoB charge (and the previously proposed SPD charge) has been a consistent part of the Authority’s proposals since 2014.[9]

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6 Second Issues Paper at [7.33(b)] and [7.62].
7 Second Issues Paper at [3.10].
8 Second Issues Paper at [7.63]-[7.64].
9 See Electricity Authority *Transmission pricing methodology review: Beneficiaries-pay options working paper* (21 January 2014) at [1.15(a)], table 2, table 3, [7.4(a)-(b)] and [7.108(a)] (in relation to the SPD charge); and Electricity Authority *Transmission pricing methodology review: TPM options working paper* (16 June 2015) at [1.56(b)-(c)], table 2, [6.59(a)]-[6.67] and table 10 (in relation to the AoB charge).

Meridian supports the definition of eligible assets proposed in the Second Issues Paper

5. Meridian's view remains that making major recent investments subject to the AoB charge provides the appropriate way to enter into the new regime. The definition of eligible investments proposed in the Second Issues Paper ensures that most of the existing assets (in value terms) are included,[10] while allowing industry understanding of the pricing mechanism and incentives to develop over time. As old investments are retired and new investments are commissioned, the scope of the AoB charge will increase naturally (and the size of the residual will correspondingly decrease).

6. Meridian agrees that the application of the AoB charge to major recent investments will better align those who benefit from those assets with those who pay for those assets and so address one of the major parts of the problem definition. However, Meridian is concerned that the expansion of the AoB charge to potentially all historic assets will threaten the durability of the TPM and is not justified by the reasons put forward by the Authority. These relate primarily to contestable ownership and potential distortions from not including all existing assets within the AoB charge. We discuss this further below.

Proposal will not be service-based or cost-reflective and will be contentious, undermining durability of a new TPM

7. It is not clear how a major expansion of the scope of the AoB charge would work. This is because the guidelines do not specify the scope of the charge or how benefits will be determined, and Transpower may create a transitional mechanism (which, it seems, may include a price cap).[11] Accordingly, it is not possible to estimate the charging consequences of the proposal. We consider this an issue in itself and inconsistent with the previous goal of minimising Transpower's discretion in the operation of the regime to implementation details.

8. What seems to be envisaged is that Transpower would devise a simple method to roughly assign asset costs to deemed beneficiaries – with the simple method potentially applicable to all pre-guidelines investments, even those valued at more than $5m. In roughly assigning costs to deemed beneficiaries there will be many points of contention:

   (i) Rather than use the RAB value, it appears that the annual amount to be recovered will be set for perhaps hundreds of aged assets as if a levelled IHC-based charge had applied (and without taking into account depreciation already recovered by Transpower). As explained in relation to refinement #4 below, this will result in the over-recovery of the costs of such assets and a breach of the NPV=0 principle. Many of Transpower's assets are largely or wholly depreciated, yet would give rise to substantial charges under this approach. Such charges will not be cost-reflective.

   (ii) Furthermore, there is unlikely to be good historic information available about the actual cost of the assets. The Authority recognises this and so proposes that a "suitable", but as yet undefined, proxy be used by Transpower.[12] This is likely to be highly contentious and the reason why such a task is generally avoided in economic regulation. As an illustration of the complexities involved, Meridian

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10 NERA Report at [28(a)]: $2.8b of $3.3b.

11 See Electricity Authority *Transmission pricing methodology: Second issues paper supplementary consultation* (13 December 2016) [Refinements Paper] at [3.3].

12 See Refinements Paper at [3.69] and [3.77].

notes that it is unclear whether the Authority intends that refurbishment work on historic assets could also give rise to an AoB charge and, if so, what data could be used.

(iii) Charges will not be allocated on the basis of actual expected benefits. That is, they will not be service-based. The Authority recognises the difficulty of determining benefits for historic assets,[13] and so the guidelines provide that:

a. Transpower will apply a simplified method to assets under $5m (clause 10) and may apply it to more expensive assets if it is not practicable to apply the standard method (clause 52 (b)); and

b. Under the simplified method, Transpower can use the residual allocators (and average injection for generation) to allocate the charge if determining benefits is not practicable (clause 17(e)).

9. In Meridian's view, this is a significant departure from the principles guiding the Authority's thinking to date. Charges determined in accordance with such an approach are likely to be strongly contested by the payers which will threaten durability.

10. Furthermore, the proposal would seem to turn this part of the AoB charge into an AoB charge in name only. In reality it will be a pseudo-residual charge (or series of pseudo-residual charges for a number of assets) and would essentially result in a smearing of the (likely disputed) "costs" of each of these assets across a limited group of participants. However, it would conflict with the principles that have guided the development of the residual charge. That is, that it should apply to a wide group of customers and only to load. Further the limited group of customers required to pay each pseudo-residual charge would not be afforded the durability-enhancing protections given to payers of the actual residual that are set out in clause 32 of the proposed guidelines. For example:

- There would be no obligation on Transpower to correct for double counting and other charging anomalies (clause 32(b)); and
- There would be no requirement that the approach result in broadly equivalent charges to customers that are in broadly equivalent circumstances (clause 32(c)).

It may be that other parts of clause 32 should also be considered in this context – for example it seems that the charge could be designed so that distributed generation could be paid for AoB charges avoided (clause 32(f)).

11. Meridian is concerned that this proposed refinement, if applied in its simplest form, risks creating a set of disputes about the allocation of an arbitrary "cost" unrelated to the RAB value, to an arbitrary set of participants who dispute being the deemed beneficiaries. We see such a charge as perpetuating the type of controversy that has accompanied HVDC charging for over two decades. Although the amounts will be smaller individually they will apply to a large number of assets, and could be very material if the Authority disregards RAB values as proposed.

12. Expanding the AoB charge would also undermine the overall price signal to transmission customers. As NERA explains, the inclusion of a large tail of AoB assets

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13 See Refinements Paper at [3.26(a)].

where both the costs and assignment of beneficiaries is disputed will produce noise rather than signal.[14]

Reasons in favour of the proposal do not justify risking harms to durability

13. Meridian does not consider that the reasons put forward for considering the expansion of the AoB charge justify such risks. The Authority lists four reasons:

    (i) To be more consistent with the DME framework;

    (ii) To support efficient decisions regarding ownership;

    (iii) To reduce potential distortions to the efficient location of load and generation; and

    (iv) To reduce the size of the residual

14. In terms of the first reason, Meridian does not consider that the sort of charge outlined above is "market like" or that it is more consistent with the DME framework. In the "Questions and Responses" accompanying the release of the Refinements Paper[15] the Authority rejected Transpower's 'simplified staged approach' on the basis that:

    > "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."

15. The same reasoning applies here where, to enable additional historical assets to fall within the AoB charge the Authority has allowed for simplification to such an extent that it may no longer be applied based on an assessment of benefits.

16. Meridian does not consider that contestable ownership should be a material factor. First, it will only be an issue for a small subset of assets. Secondly, the Authority does not appear to have considered the implications of the Part 4 regime on hold/sell decisions for Transpower. In particular, our understanding is that:

    - The effect of: (a) the wash-up mechanism in clauses 21-24 of Transpower's IPP determination; and (b) the "Gain/(loss) on disposal of assets" line item in Schedule E, is that any profit (or loss) on the sale flows through to the next Forecast Maximum Allowable Revenue (**MAR**).

    - That is, Transpower makes an NPV=0 return on the asset *regardless of the sale price*.

    - Furthermore, where the purchaser is an Electricity Distribution Business, it would need to enter the asset into its RAB at the value it appeared in Transpower's RAB, again regardless of the transaction price.[16]

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[14] NERA Report at [27]-[29].

[15] "Questions and Responses", available at: <http://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/development/questions-and-responses/>.

[16] Commerce Commission *Electricity Distribution Services Input Methodologies Determination 2012* (consolidated 3 February 2016) at clause 2.2.11(1)(e).

17. Accordingly, while asset-specific charges will make a customer a more willing purchaser, since Transpower is indifferent to the transaction price, asset sales will be based on its preference as to whether to own or sell the asset and not efficiency in any objective or market sense.

18. In light of the limited number of assets to which contestable ownership considerations may apply and the incentives created by Part 4, we consider that the Authority should disregard contestable ownership as a relevant factor.

19. In terms of distortions of generation and load locational decisions, Meridian considers that this is a purely hypothetical issue. Boundary issues may arise in theory, but it is just one of a large number of approximations within the TPM. Others include asset values, time profiles and *ex ante* determination of beneficiaries.

20. The view that this boundary issue is especially important seems to be based on false scientism and not informed by the overall pragmatic nature of the TPM. Furthermore, the proposed solution as described above seems likely to create more distortions than it solves. The Authority recognises the potential for such distortions to drive inefficient behavioural change[17] but dismisses this risk on the basis that the material change of circumstances test necessary to trigger a re-allocation of benefits would not be met except in situations of “exceptional changes in demand”. Obviously, “exceptional change” is not the same thing as “material change” and the fact that the Authority seems to be contemplating a different and harder test for reallocation of the charges created by this refinement is recognition of its potentially distortionary effect.

21. Finally, in terms of the size of the residual charge, Meridian notes that the residual is designed to be non-distortionary and that over time that charge will reduce significantly, as old assets depreciate and new assets are built and charged for using the AoB charge.

22. For these reasons Meridian continues to support the proposed inclusion of assets in the AoB charge as set out in the Second Issues Paper. We consider the definition of “eligible investments” to be robust and durable, and should not be extended. In our view, the Authority should focus on the big gains to be made from TPM reform (beneficiaries-pay for major recent investments and scrutiny of future transmission investments) and be wary of last-minute side-issues creating more problems than they solve.

The Authority rather than Transpower is the appropriate decision-maker

23. Meridian strongly opposes the proposal that the decision about which assets are to be included for the AoB charge should be left to Transpower, or that Transpower should be left to determine whether and what transitional arrangements will apply.

24. Determining eligibility for the AoB charge is a question of policy that ultimately requires expert policy judgment. It is not a question of technical implementation. This means the Authority, rather than Transpower, is in a better position to make that decision.[18]

[17] Refinements Paper at [3.13(b)]

[18] See also the framework proposed by Castalia Strategic Advisors *Ensuring an improved transmission pricing methodology: report to Genesis Energy* (July 2016) at pp 5-7, which reaches the same conclusion that the Authority is the appropriate decision-maker.

25. Transpower is not neutral on the scope of the AoB charge or on the methodology for allocating costs of assets subject to the AoB charge.[19] Both will impact the level of scrutiny it will face and the latter in particular will impact on how much effort it will need to put in to allocating charges according to benefits. Transpower's support for a broader AoB charge and a lower residual[20] has been premised on Transpower being able to use very simplified methodologies that do not necessarily align charges with benefits and instead treat asset location as a rough proxy for benefit.[21] It has also indicated that in its view applying non-simplified methodologies to older eligible investments is to some extent "speculative".[22] It would also be natural for Transpower to favour higher asset-specific charges so that it can dispose of assets it would rather not carry.[23]

26. As NERA sets out, Transpower is subject to a revenue cap, which as economic theory and the Authority's own submission to the Commerce Commission point out, creates poor incentives for pricing efficiency. It may also provide Transpower with an incentive to prefer grid solutions to alternatives. In addition Transpower is likely to give greater weight to transaction costs over pricing efficiency.[24] Moreover, it is not Transpower but the Authority that has "a clear mandate to act in the best interests of society".[25]

27. Leaving policy issues to Transpower about which it has already expressed firm views as a submitter in the Authority's process gives rise to administrative law issues and risks undermining the durability of the resulting TPM. We agree that "the Authority needs to be cautious in delegation … to Transpower, as the incentives and objectives of Transpower will not always align with the Authority's".[26]

28. While the Authority has the final say in terms of approving the TPM, Meridian is concerned that by the time the TPM returns to the Authority for approval, Transpower's decisions will have momentum and any significant changes will delay implementation. As discussed by NERA, leaving too much for final review brings its own problems:[27]

> … Transpower has no comparative advantage in carrying out the tasks discussed above, and given its incentives may not be aligned with the Authority's, it would seem more time efficient for the Authority to simply carry out the analysis and make the decisions itself, or to at least develop the framework, leaving just the implementation to Transpower. Given the likely time pressures, it is unlikely the Authority would have the will or ability to start the analysis again, even if it was not happy with Transpower's design proposals and decisions. So there is a risk of sub-optimal TPM outcomes. And to the degree the Authority does do its own analysis, there would be duplication of resources.

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19 A point noted in the NERA Report at [110]-[111].

20 See Transpower *Submission: Transmission pricing methodology, 2nd issues and proposals paper* (26 July 2016) at p 19 (the AoB charge should apply to "as much of the grid as possible").

21 See Transpower *Submission: Transmission pricing methodology, 2nd issues and proposals paper* (26 July 2016) at p 8 (Transpower sees Authority's proposals as "overly intricate solutions" that "provide a false precision") and pp 6, 8 and 12 (preference for using asset location and value as the "primary proxy for benefit".

22 See Transpower *Submission: Transmission pricing methodology, 2nd issues and proposals paper* (26 July 2016) at p 13.

23 As noted in the Refinements Paper at [3.11(b)] and footnote 39.

24 NERA Report at [104]-[111].

25 NERA Report at [109].

26 NERA Report at [14].

27 NERA Report at [112].

2. The calculation of benefits will trade off accuracy against practicality

29. The trade-off between accuracy and practicality should take into account Meridian's submissions in relation to refinement #1. For historic assets in particular, the trade-off should be considered when decisions about what assets to include in the AoB charge are being made – which Meridian submits is best done now, by the Authority.

30. Subject to these comments, Meridian supports the following aspects of the Authority's articulation of the trade-off between accuracy and practicality:[28]

- The method for calculating benefits for the AoB charge must be based on expected positive net private benefit.
- Any method must be as accurate as is reasonably practicable.
- Minimal discretion will continue to be a key factor in the design of the methods for determining benefits, so that Transpower's determination of benefits would not be subjective.

31. Unfortunately the current drafting of the guidelines does not give sufficient weight to these aspects in its articulation of the trade-off and Meridian suggests that the guidelines should be amended to ensure they do.

32. Meridian also considers that empowering Transpower to seek a determination from the Authority to help ensure a robust estimate of benefits is sensible.

33. As discussed in more detail in refinement #4 below, and in the Read Report, the guidelines should include key principles about fundamental features of the AoB charge, such as calculation of benefits.

3. The calculation of net private benefits for the AoB charge to include LCE

34. Meridian agrees that on a net benefit approach, a customer's net private benefit in relation to an investment should take into account any increase or decrease in the amount of LCE the customer would receive following the commissioning of the investment. A change in LCE payments is a relevant part of a net benefit calculation and therefore should be included. Meridian repeats its submission made in response to the Second Issues Paper that the calculation of net private benefits should include benefits arising in ancillary services markets including instantaneous reserve and frequency keeping markets.

4. The annual AoB charges for an investment to be service-based and cost-reflective

Introduction

35. Meridian's greatest concern in relation to the Refinements Paper is the proposal that the revenue requirement for existing assets will be set without taking into account depreciation funded by transmission customers to date. Such an approach will result in charges which are not cost-reflective because transmission customers will over-pay

28 Refinements Paper at [3.18(a)-(b)] and footnote 43.

for these assets. The extent of total overpayment in relation to Pole 2 and Pole 3 alone could be in the order of $400m over their remaining lifetimes.

36. The Authority proposes setting the annual revenue requirement for an existing asset as if a levelled indexed historic cost (**IHC**) based charge had applied since it was commissioned. This contrasts with its proposal in the Second Issues Paper. While Meridian is broadly comfortable with such an approach for new assets, it cannot be applied to existing assets without breaching the principle that the total AoB revenue collected for an asset should match the cost of the asset plus the capital cost of holding the asset (in other words, a "normal" or NPV=0 return).[29] As NERA states, NPV=0 is "a fundamental principle of regulatory economics".[30]

37. Existing HVDC and HVAC interconnection assets are included in Transpower's regulated asset base (**RAB**) and contribute to its maximum allowable revenue (MAR) on a discounted historic cost (**DHC**) basis with straight line depreciation.[31] This approach "front loads" depreciation and produces a downward sloping time profile for charges. The resulting HVDC and HVAC interconnection revenue requirements are funded under the current TPM through the HVDC and Interconnection charges respectively. The use of this valuation methodology under Part 4 was a conscious decision (supported by Transpower),[32] and the approach has been confirmed in the recent input methodologies review.[33]

38. While the total recovery should be the same under either valuation methodology if applied over the full lifetime of an asset, switching from a DHC-based charge to an IHC-based levelled charge part way through an asset's life will breach the NPV=0 principle and result in an over-recovery of costs.[34] The sloped DHC-based approach implies higher charges in earlier years than the levelled approach. These higher payments are then offset by lower charges in later years. If there is a switch part way through the asset's life, then the higher initial DHC-based charges are never offset and customers will overpay for the asset.

39. The figure below (which is explained in further detail in Appendix 1) illustrates the overpayment for a stylised version of Pole 2. The orange line represents the DHC-based revenue requirement and the blue line represents the levelled IHC-based revenue requirement. If the change occurs in 2017 (the dotted vertical line), then the area between the blue and orange lines between 2017 and 2032 represents the total overpayment:

29 Refinements Paper at [3.43]-[3.44].

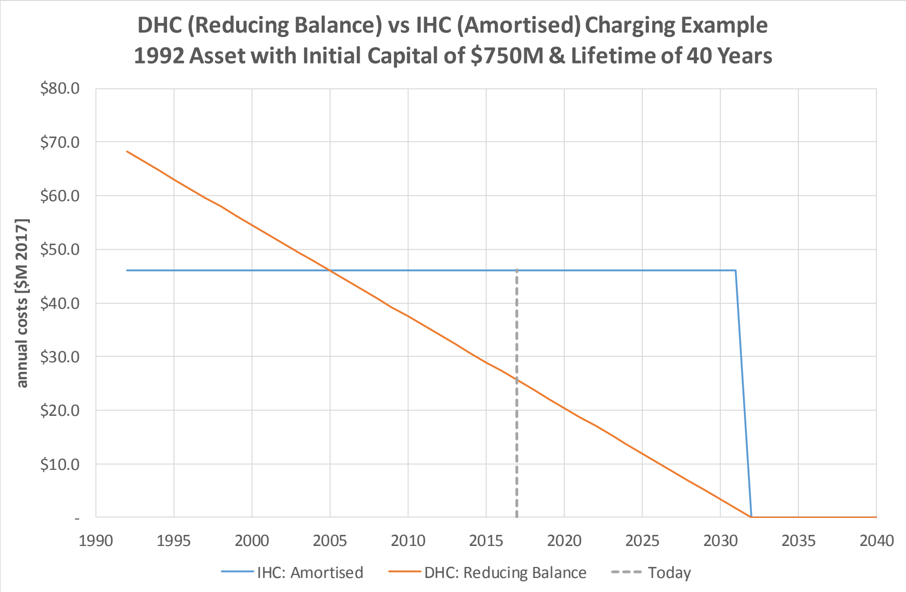
30 NERA Report at [39].

31 Note that as a result of the Administrative Settlement with the Commerce Commission, Transpower's ODRC values were deemed to be DHC values.

32 See Transpower *Explanatory Material to Transpower's Formal Settlement Proposal* (19 September 2007) at section 4.4.

33 Commerce Commission *Input Methodologies (Transpower) Reasons Paper* (December 2010) at [4.3.4]-[4.3.17] and [4.4.104]-[4.4.108].

34 See NERA Report at [52].



40. In addition to switching from DHC to IHC, the Authority proposes that the levelled charge will be set using a contemporary estimate of the asset's total life.[35] This raises a "similar over-recovery issue".[36] Where the new estimate of the asset's life is greater than the estimate used for DHC purposes in the RAB, the extent of over-recovery will increase (see [21] to [26] in Appendix 1 and the NERA Report[37]).

41. Such outcomes would be inconsistent with standard principles of price regulation and with the Authority's own articulation of what it means for a charge to be cost-reflective.[38] Accordingly, Meridian considers that the Authority must specify in the guidelines that AoB charges for existing assets must account for depreciation on those assets as reflected in the present RAB values. Providing this is done (i.e. recovery is capped at present RAB value), the recovery of the remaining revenue can be levelled over the remaining life of the asset.

42. Using present RAB values will also avoid the need for Transpower to assess the historical costs of old assets to recreate the levelled charge that would have applied from the start of the asset's life. The Authority suggests that where such historic cost information is not available Transpower should use a "suitable proxy" in such a case.[39] This would likely prove to be extremely controversial compared with using the depreciated RAB values which have been endorsed through the Commerce Commission's processes. However, the problem is avoided by using the present RAB values consistently with Part 4.[40]

43. While the principles discussed above apply for all existing assets that will be subject to the AoB charge, additional considerations apply in relation to the HVDC assets which South Island generators have paid for over the last two decades based on a building blocks approach using DHC asset valuations.

35 Refinements Paper at [3.56]-[3.61].
36 NERA Report at [54].
37 NERA Report at [56].
38 Second Issues Paper at [5.11].
39 Refinements Paper at [3.76]-[3.77].
40 For more detailed analysis about inconsistency with the Commerce Commission's regime, see the NERA Report at section 3.2.1.2.

44. In the Second Issues Paper the Authority agreed that a switch in valuation methodologies would result in customers "being charged more than the full cost of the assets they use, seriously breaching the principle of cost-reflectiveness".[41] However, the Authority now appears comfortable with such an outcome on the basis that socialisation of the costs of HVAC interconnection assets through the postage stamp charge means that no single customer has to date paid a substantial portion of any particular asset.[42] Even if such an argument was correct in relation to the HVAC interconnection assets (and Meridian certainly does not accept it), it can have no application to the HVDC assets where specific customers have faced charges for specific assets and have directly funded the revenue requirement implied by the DHC valuation approach.[43] And in all cases, as Professor Littlechild explains, the switch to IHC "means that the total price to certain customers will not be related to the cost of providing that service", but rather:[44]

> … will depend on a rather random combination of the amount that happens to have been paid to date based on the previous methodology and the amount going forward that is implied by a new methodology, a combination that has no economic significance or merit. The total paid for an asset over its lifetime would vary arbitrarily depending on how much of its life had passed at the time the new TPM took effect.

45. The Authority has not published any analysis on the extent of over-recovery or impact on charges. In Appendix 1 we illustrate how the over-payments arise both by disregarding the front-loading of depreciation which has occurred through the DHC-based approach and where the asset life is extended by using a new estimate. Using a stylised model of Pole 2 and Pole 3 represented by a $750m asset with a 40 year life commissioned in 1992 and 2013, Appendix 1 estimates overpayments of $310m and $85m respectively.

46. One of the main parts of the problem definition that the new TPM is intended to solve is the arbitrary treatment of charging for the HVDC assets. Under the present regime, Meridian has paid (in 2017 dollars) approximately $1.5 billion in HVDC charges, of which approximately $1 billion has been towards capital costs. In total, South Island generators have paid approximately $1.4 billion towards capital costs on the HVDC assets. A "solution" that ignores depreciation funded by past HVDC charges will give rise to a new set of durability issues. As NERA states, "it would not make sense to replace that mechanism [i.e. the current TPM] with another one that would be perceived as inefficient and unfair."[45] "Ignoring this payment history and the NPV=0 principle would undermine confidence in the new regime, and therefore its durability."[46] Depending on the benefit calculations ultimately applied by Transpower and the extent to which any revaluation increases the value of HVDC assets, it is theoretically possible that South Island generators would pay more in dollar terms than they would if the present HVDC methodology simply continued (that is, if the decrease in their share of the payment is outweighed by the increase in total payments). This is not a reasonable or rational solution to the problems identified by the Authority.

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41 Second Issues Paper at [7.161].
42 Refinements Paper at [3.58].
43 Littlechild Report at [5]-[6].
44 Littlechild Report at [6]-[7].
45 NERA Report at [62].
46 NERA Report at [64].

47. In relation to AoB charges for existing assets, this section covers the following topics in turn:

- Changing valuation approaches to existing assets is inconsistent with cost-reflectivity and regulatory jurisprudence;
- HVDC-specific issues; and
- Potential unintended consequences of a divergence between the value of an asset in the RAB and the value implied by the TPM.

48. In addition to the over-recovery issue, Meridian considers that the draft guidelines do not strike an appropriate balance between prescription and discretion. There are some matters that should be locked down in the guidelines but which are not (such as the scope of the AoB charge and the treatment of past payments), and other areas where Transpower should have more discretion. We turn to this topic at the end of this section.

Changing valuation approaches to existing assets is inconsistent with cost-reflectivity and regulatory jurisprudence

49. As set out above, the Authority's proposals to set annual revenue requirements for existing assets on the basis of an IHC-based approach and, potentially, to extend charges over an updated and longer estimate of the asset's life, will increase the total revenue recovered over the life of the asset. This means that the implied value of the asset for TPM purposes will be higher than the more heavily depreciated RAB value of the asset.

50. Accordingly the Authority's proposal would produce a "revaluation gain". It is a well-established part of the jurisprudence of price regulation that allowing such revaluation gains would cause an excessive return (that is, in breach of the NPV=0 principle). In order to prevent an excessive return, either the revaluation gain can be treated as income (which neutralises the effect of the increased valuation) or else revaluations should simply be avoided.

51. In terms of the first approach, in establishing the input methodologies that give effect to the Part 4 price control regime in 2010, the Commerce Commission endorsed the "fundamental principle" that:[47]

> upward changes in asset values represent a form of income to the provider of infrastructure services and so need to be netted off from revenue that is to be recovered from charges for the use of those assets.

52. The Commission noted that such an approach was required to meet NPV=0 and financial capital maintenance principles (that is, the expectation of a normal return over the lifetime of an asset) and was consistent with outcomes in workably competitive markets.[48]

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47 Commerce Commission *Input Methodologies (Electricity Distribution and Gas Pipeline Services) Reasons Paper* (December 2010) at [2.8.16] (quoting a submission from NERA on behalf of Orion).

48 Commerce Commission *Input Methodologies (Electricity Distribution and Gas Pipeline Services) Reasons Paper* (December 2010) at [2.8.14]-[2.8.18].

53. In the subsequent "Merits Review appeal", the High Court (with two expert lay members) agreed that revaluation gains would result in excessive returns and opposed the adoption of new higher valuations at the commencement of a price control regime:[49]

> Because a supplier's allowed maximum revenue (or assessed return) is derived in part from the value of the RAB, an increase in valuation directly affects the level of allowed revenue. In other words, in the absence of a regulatory constraint a regulated supplier could increase its allowed revenue simply by revaluing its assets, without any increase in investment or efficiency. Higher profits resulting from such a revaluation would be a windfall gain rather than a reward for superior performance, which is contrary to the long term benefit of consumers, and to the objective in s 52A(1)(d) of limiting a supplier's ability to extract excessive profits. …

54. The Supreme Court has also addressed the issue of choosing between actual depreciated asset values and using new hypothetical values in *Vodafone New Zealand Ltd v Telecom New Zealand Ltd* (*Vodafone TSO*). In the *Vodafone TSO* case, the Supreme Court considered whether the Commerce Commission had erred in law when determining the net cost to an efficient service provider for supplying certain services. In calculating the net cost, the Commission had decided to use optimised replacement costs (ORC) of the hypothetical network the efficient service provider would use.

55. The Court held that the Commission had erred by using new higher asset values rather than the actual values of existing depreciated assets. The key part of the majority opinion was as follows:[50]

> The Commission's use of ORC failed to address, however, the distortion caused by artificially revaluing old assets (already wholly or partly depreciated) which were in reality not likely to be replaced and optimised. It is sensible to revalue on an optimised basis, say, a switch by attributing to it the lower value (price) of a new switch which performs the same or better function but is able to be acquired at a lesser price. It is quite another thing to attribute a modern equivalent value to an old asset which is not actually being replaced and for which no replacement would sensibly be introduced. *All that does is to artificially inflate the value of the old asset and provide a windfall for the firm in terms of an enhanced return on and of capital employed.*

56. These authorities are directly applicable to the determination of the annual AoB revenue requirement for the assets already existing in Transpower's RAB at depreciated values. While those decisions related to the aggregate revenue being collected by the supplier, they apply equally to the question of determining the value of an asset which will be subject to a cost-reflective charge. As the reasoning above indicates, a Court is unlikely to accept that depreciated assets can be given a new higher valuation.

57. The Authority itself expressed a similar sentiment in the Second Issues Paper in reaching its original view that DHC values would be used for existing assets:

> 7.161 In particular, moving from DHC to RC [or IHC] for customers with heavily depreciated assets would result in those customers being charged more than the full cost of the assets they use, seriously breaching the principle of cost-reflectiveness discussed in chapter 5. This is because the costs of heavily depreciated assets would have already been largely recovered through existing charges. In addition, they may affect perceptions of fairness, and so reduce the durability of the proposed TPM. As with other factors that could undermine

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49 *Wellington International Airport Ltd v Commerce Commission* [2013] NZHC 3289 at [383].

50 *Vodafone New Zealand Ltd v Telecom New Zealand Ltd* [2011] NZSC 138, [2012] 3 NZLR 153 at [70] (emphasis added).

durability, this could give rise to uncertainty and therefore adversely affect investment efficiency.

58. Despite this, in the Refinements Paper the Authority proposes a levelled IHC-based charge based on the hypothetical construct that it had applied since the investment was commissioned and using a contemporary estimate of the remaining asset life. The Authority appears to have become comfortable with this approach on the basis that: (1) Transpower is still constrained by the MAR; and (2) postage stamp pricing that currently applies to HVAC assets means that no single customer has paid a significant share of any particular asset (rather, everyone has paid a little bit towards many assets), and so no customer will "pay twice" for an asset on account of the revaluation.

59. In Meridian's view, past socialisation of HVAC interconnection charges and the existence of the MAR are not relevant factors. The question is not whether a single customer may "pay twice", but whether the charges for the asset overall exceed the NPV=0 threshold.[51] In the words of the Authority, cost-reflectivity requires that "the prices charged for access to the asset accurately reflect its cost, and they do not over or under-recover that cost".[52] Similarly, while the MAR cap will prevent Transpower over-recovering in aggregate, the failure to take into account past depreciation will result in AoB beneficiaries overpaying with residual payers enjoying a windfall reduction.[53] "[T]hese concerns cannot be ignored just because Transpower is restricted to earning its MAR. Cost reflectivity at an asset-specific level is important for the durability of the proposed regime."[54]

60. Meridian's position is that compliance with cost-reflectivity principles means that future charges for existing assets must take into account past payments as reflected in the present RAB values. The two obvious alternatives are either to set a sloped annual revenue requirement as implied by the RAB and Part 4 methodology, or to determine the total revenue that remains to be collected under Part 4 and to turn that amount into a levelled annuity. As NERA notes, "the Authority's objective of a flat cost recovery could be achieved by turning the (unrecovered) present value of the (Commission's) asset cost into an annuity (using the Commission's nominal WACC)".[55]

61. The Authority suggests two advantages of applying an IHC-based charge to existing assets: avoiding a high DHC-based charge for newer pre-guidelines investments and having a charge that is more service-based.[56] Levelling the remaining revenue to be collected would fulfil both these goals in the same way that an IHC-based charge would.

62. First, the use of newer assets will not be discouraged if the remaining revenue to be collected is used to determine a levelled charge.

63. Secondly, such a charge would meet the Authority's goal of charging at the same level irrespective of the age of the asset. While such a charge will be lower than if an IHC-based approach had applied from the commissioning date, the difference simply reflects the reality that depreciation has been front loaded to date and this has been reflected in charges to date.

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51 NERA Report at [60].

52 Second Issues Paper at [7.146].

53 This windfall may be significant. The stylised quantification in the appendix calculates it to be $400m in DCF terms for the HVDC. We haven't attempted to quantify the figure across all of the 11 named-eligible investments

54 NERA Report at [61].

55 NERA Report at [72].

56 Refinements Paper at [3.56].

64. As the High Court noted in the Merits Review appeal, workably competitive markets tend towards NPV=0 returns, but this does not imply particular prices at particular times:[57]

> [18] In our view, what matters is that workably competitive markets have a tendency towards generating certain outcomes. These outcomes include the earning by firms of normal rates of return, and the existence of prices that reflect such normal rates of return, after covering the firms' efficient costs.
>
> [19] Of course, firms may earn higher than normal rates of return for extended periods. On the other hand, firms may earn rates of return less than they expected and less than commensurate with the risks faced by their owners when they made their investments. They may even make losses for extended periods. Prices in workably competitive markets may never exactly reflect efficient costs, including a normal rate of return.
>
> [20] But the *tendencies* in workably competitive markets are towards such returns and prices. By themselves, these tendencies will also lead towards incentives for efficient investment (investment that is reasonably expected to earn at least a normal rate of return) and innovation. That is to say, the prices that tend to be generated in workably competitive markets will provide incentives for efficient investment and for innovation.

65. The Court's analysis is consistent with modern economic theory. As Professor Littlechild explains, "[w]hile real world competitive markets will tend towards normal (or NPV=0) returns, such markets do not produce strong predictions about how charges will vary over time. Furthermore, in such markets, different assets may have charges set on different bases."[58] Analysis by NERA similarly finds that although "prices might tend towards the competitive level", they will oscillate and the competitive level itself will vary over time.[59]

66. Competitive markets have these features because there are many economic and other business considerations from both customer and supplier that lead to particular prices at particular times.[60]

67. In the case of historic assets, it is a "fiction" to suppose that IHC-based charging had applied from the date of commissioning".[61] Rather, and to the detriment of cost-reflectivity:[62]

> The proposal to apply IHC-based levelled charges appears to be driven by the assumption that, in workably competitive markets, charges are constant over time. This seems to me an abstract proposition that is not characteristic of real competitive markets, particularly when benefits, demand and technologies are changing over time. This assumption should not be allowed to compromise the achievement of other more important considerations such as cost-reflectivity.

68. While "setting the time profile of the charge to be level would be convenient, [it] should not be justified on the grounds of workably competitive market outcomes. Further, the convenience of a levelled charge does not require nor justify setting the charge at a level which results in over-recovery in respect of historic assets."[63]

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57 *Wellington International Airport Ltd v Commerce Commission* [2013] NZHC 3289.
58 Littlechild Report at [17].
59 NERA Report at [66].
60 Littlechild Report at [16].
61 Littlechild Report at [19].
62 Littlechild Report at [20].
63 NERA Report at [73].

69. Accordingly Meridian considers that a levelled charge that collected only the remaining revenue is no less "service-based" than a levelled charge set as if an IHC-based approach had been taken historically. Certainly, the difference in levels does not justify breaching cost-recovery principles and risking durability. Indeed, it would be remarkable if the Authority imposed a new asset valuation for charging purposes when the Commerce Commission rejected such an approach in determining the total revenue to be recovered. We doubt that this would pass the test of consistency in clause 12.89 of the Code. As with the proposed extension of the scope of the AoB charge, Meridian considers that the Authority should focus on implementing a robust and durable TPM without aiming for false precision or attempting to solve boundary issues that do not appear to be of any practical importance.

HVDC-specific issues

70. As set out above, the Authority proposes disregarding depreciation on existing assets on the basis that the socialisation of interconnection charges means that no single customer has paid a significant portion of any particular asset. Meridian disagrees with this proposition in general for the reasons set out above. However, in addition, it is clear that it cannot apply with respect to the HVDC assets as these assets have been subject to a targeted charge and not to a postage stamp methodology.[64]

71. Notwithstanding changes to the structure of the industry, the identity of the regulators and the regulatory mechanisms used to impose price control, over at least the last 20 years HVDC charges have been imposed on South Island generators in a consistent manner. The charges have been set based on a return on and of the HVDC assets and the customers have had clear visibility of assets with diminishing book values. This regulatory history is reflected in:

- Transpower's *Pricing for grid connection services* (the 2001 TPM);[65]
- Government policy statements issued from December 2000 to 2009;[66]
- Proposals, submissions, and draft and final decisions relating to the Administrative Settlement;[67] and
- Consulting work commissioned by the Electricity Commission.[68]

72. The existence of an "HVDC revenue" stream to be recovered is present throughout the Part 4 price control regime and flows directly into the TPM. For the HVDC assets, there is a tight link between the building blocks which set the allowable revenue and

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64 Charges for the HVDC assets have been set by: (a) considering the HVDC assets separately; (b) calculating an annual revenue requirement based on a building blocks model which has incorporated a return on the assets and depreciation of the assets; and (c) imposing that charge on a distinct subset of customers (being South Island generators since 1996).

65 Transpower *Pricing for grid connection service* (December 2000) at pp 6 and 8; sections [2.3], [3.1] and [3.6]; and Appendices B, C and K.

66 For example: Government Policy Statement (December 2000) at [24] and Appendix 1 at [6]-[7]; (February 2002); and (May 2009) at [97].

67 See Transpower S*ubmission to the Commerce Commission on the Intention to Declare Control* (February 2006) at [106], [130], [246]-[249], [288], [335]-[336] and [453]; Transpower *Explanatory Material to Transpower's Formal Settlement Proposal* (19 September 2007) at [5]; Commerce Commission *Draft Decisions and Reasons for Not Declaring Control* (5 October 2007) at [141] and Final Decision (13 May 2008) at [141].

68 Strata Energy Consulting Ltd *Report on Transmission Pricing Methodologies 1988-2008* (June 2009) at [8]-[10], [13], [15], [17], [23] and accompanying table and charts.

the TPM which allocates this to customers as if it was a separate regulated business in its own right. The HVDC assets have been treated as a self-contained “mini-RAB” with additions and depreciation being determined in accordance with standard building block principles over this period.

73. Meridian has strongly objected to the separate treatment of HVDC assets and to the deeming of South Island generators as the sole beneficiaries of those assets. However, “ignoring this payment history and the NPV=0 principle would undermine confidence in the new regime, and therefore its durability.”[69] In correcting the arbitrary and inefficient setting of HVDC charges historically, no reasonable decision-maker could ignore the reality that many of the HVDC assets have been largely depreciated.

74. It is difficult to precisely estimate the extent of over-recovery that would occur if the annual revenue to be collected under AoB charges for the HVDC assets was set as if an IHC-based levelled charge had applied since the assets were commissioned. This would require a detailed analysis of the build-up of HVDC charges since 1988. However, Appendix 1 contains a stylised model to estimate the over-recovery.

75. Indicatively:

- For Pole 2, the over-recovery from DCF would be in the order of $310m (or $435m if the asset life was re-estimated and another 10 years added).
- For Pole 3, the over-recovery from DCF would be in the order of $85m (or $95m if the asset life was re-estimated and another 10 years added).

76. Such an outcome would be a clear violation of the NPV=0 principle for cost-reflective pricing that has been adopted by the Authority. As quoted above, “the costs of heavily depreciated assets [which] would have already been largely recovered through existing charges” cannot be assigned a new higher value without “seriously breaching the principle of cost-reflectiveness”.[70]

77. The principles in the *Vodafone TSO* case and the Merits Review appeal are directly applicable to the HVDC “mini-RAB”. That is, South Island generators have been paying for the HVDC assets in accordance with conventional building blocks principles. This concept is recognised within both the Part 4 regime and the TPM. Adopting a new valuation approach without taking into account that funding of depreciation would be an unlawful outcome as it would “artificially inflate” the amount paid by the customers and give a “windfall” to those who pay for other assets under the residual.[71] The HVDC beneficiaries under the AoB charge would overpay for these assets and, as discussed above, the MAR cap simply means that it is payers of the residual, rather than Transpower, who would enjoy this windfall.

78. Moreover, Professor Littlechild’s assessment is that refinement #4 would undermine the Authority’s proposed reforms:[72]

> This would seem not only inconsistent and inequitable in particular cases, it would also seem to undermine the thrust of the present reforms. They comprise revised pricing arrangements that are more principled and most closely reflective of costs and benefits for particular assets and customers groups more closely reflecting what would happen in competitive markets.

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69 NERA Report at [64].
70 Second Issues Paper at [7.161].
71 At [72].
72 Littlechild Report at [8].

This is intended to give better price signals to users that will improve decision-making, ultimately to the benefits of customers generally. Yet these reforms are now to be modified by a rather abstract requirement that seems to over-rule the economic analysis underlying the proposed reforms, thereby raising questions as to the soundness and durability of the earlier proposals.

79. An efficient charge for the HVDC assets is one that will generate an NPV=0 return taking into account past depreciation as reflected in the current RAB values. While the Authority may consider that it would have been preferable to have adopted a levelled charge historically, future charges must recognise what has actually occurred in practice. If a levelled charge is adopted it must be one which collects only the remaining revenue implied by the RAB values.

80. The HVDC charge has operated as a form of badly designed beneficiaries-pay pricing over the last two decades (with South Island generators wrongly deemed to be the sole beneficiaries). Moving the HVDC assets into the AoB regime is analogous to updating the AoB beneficiaries for an asset where there is a material change of circumstances review. In the same way that NPV=0 principles would apply when such an adjustment occurs even though the identity and shares of the beneficiaries change, the Authority must take into account past HVDC payments now. There is no sound reason to depart from cost reflectivity even if it were able to be established that no single party will "pay twice".

81. Stepping back, the arbitrary imposition of HVDC costs on South Island generators has been one of the main parts of the Authority's problem definition for the TPM. As the Authority has noted for some time, "Unsurprisingly, the HVDC charge has been highly controversial and the subject of lobbying and disputes for many years. It is therefore unlikely to be durable."[73]

82. If the HVDC assets are included in the AoB charge without recognising the amounts paid to date, then, depending on relative shares of the benefits ultimately calculated by Transpower and the extent of HVDC revaluation, South Island generators might theoretically pay more in dollar terms than if the present disputed HVDC charge simply continued. They will certainly be paying much more than they could fairly and reasonably expect to pay given the history of the HVDC charge and their funding to date of depreciation on HVDC assets.

83. Meridian is not seeking special treatment of the HVDC assets, nor is asset valuation a mere "wealth transfer" issue. It is rather seeking that HVDC assets are incorporated into the AoB charging regime in a way that respects NPV=0 and the history of past HVDC charges.

84. If the Authority takes into account past depreciation as reflected in the current RAB values it will result in charges which are cost-reflective and durable. However, if the Authority sets levelled charges that ignore past payments, then:

- <u>Charges will not be cost-reflective</u>: The resulting charges will not be cost reflective or efficient, and will be inconsistent with the Authority's own statements as to the importance of cost-reflectivity.
- <u>Durability issues will persist</u>: Far from solving past HVDC issues, it will compound matters and will not produce a durable charge.

73 Electricity Authority *Transmission Pricing Methodology: Problem Definition relating to Interconnection and HVDC Assets: Working Paper* (16 September 2014) at [10.8]; see also Second Issues Paper at [6.95].

- The Authority will be signalling that it may depart from NPV=0 in the future: The Authority will signal that it is not concerned about applying the NPV=0 principle to historic assets. As all future assets will eventually be historic assets, participants will take this uncertainty into account in assessing new transmission investment proposals and in making their own investment decisions.

- The approach may be subject to legal challenge: The Authority would be at risk of a legal challenge on the basis that the proposed treatment of HVDC assets was inconsistent with the Part 4 price control regime and/or unlawful in the same way that the Commerce Commission's approach to charging was found to be unlawful in the *Vodafone TSO* case.

85. Given the history of the HVDC charge, the only viable (cost-reflective) approach to bringing these assets within the AoB regime is to take into account the extent to which the HVDC assets have already been depreciated and paid for under the present TPM and Part 4 of the Commerce Act. As with existing assets generally, the remaining revenue to be collected should be levelled over the assets' remaining lives.

86. At the very least, Pole 2 (and any other similarly dated assets) should either be removed from the AoB charge or have past deprecation taken into account.

87. Finally, Meridian notes the existence of assets that are "HVDC assets" but do not come within the definitions of "Pole 2 of the HVDC link" and/or Pole 3 (being "the HVDC Project approved by the Electricity Commission on 25 September 2008"). The principles discussed above would also apply to any such assets that become subject to the AoB charge.

Risk of unintended consequences

88. Meridian is also concerned about unintended consequences from the proposal.

89. The Authority's proposed approach to AoB charges will cause a divergence between:

    (i) how much an asset will in total contribute to Transpower's MAR going forward; and

    (ii) how much Transpower will charge for the asset in total under the TPM going forward.

90. The total revenue to be collected starts off the same under either approach for a new asset.[74] However, as recovery is front-loaded under the Part 4 DHC-based approach with straight line depreciation, the total amount remaining to be collected is lower than under the TPM from the end of the first year until the end of the asset's life. So, for example, a heavily depreciated asset will earn much more under the TPM than it contributes to the MAR over the remaining asset life.

91. A potential unintended consequence of this divergence is that it may provide Transpower with a financial incentive to sell the assets in question as it could secure a greater return than it would if they remained in the RAB.[75] This would artificially distort hold/sell decisions and also risk undermining the NPV=0 principle of Part 4 price control.

[74] Refinements Paper at [3.43]-[3.52].

[75] See NERA Report at [71].

92. From Meridian's understanding of the wash-up calculation in Transpower's IPP sales revenue above the RAB value of the asset would be included in determining Transpower's future MAR and so the incentive would be neutralised. However, we consider that:

(i) This is an issue that the Authority should monitor.

(ii) Divergence from the Part 4 revenue requirements for a particular asset should be minimised. For example, it is preferable to use asset lives from the RAB rather than separate ones for TPM purposes.

(iii) The existence of the risk suggests Transpower is not a neutral party when it comes to issues such as deciding the assets to be covered by the AoB charge, time profile of recovery and asset valuation. These must instead be determined by the Authority.

Comments on the draft guidelines and Transpower discretion

93. To avoid extended future debates about their meaning, the guidelines should be drafted so they can be understood by someone who has not been involved in the process to date. For example, clear statements should be made as to the intention of the TPM as a whole and of each individual charge. In addition, for matters where the Authority is the appropriate decision-maker, principles should be determined now and not left for further consultation by Transpower.

94. Meridian is concerned that the draft guidelines, and the AoB clauses in particular, do not set a clear path for Transpower to follow in preparing the TPM. For example:

- There is no overall map as to the charging components of the TPM, potentially important elements appear late in the guidelines (such as the LRMC charge), and relationships between the charges are not spelt out clearly.

- There is too much detail on some minor points (such as details relating to the price cap), while many major points are left unexplained (such as statements about the purpose and basic structure of the AoB charge).

- Refinements #1 and #4 would provide for Transpower to make decisions on matters such as the scope of the AoB charge and asset valuation issues even though the Authority is the more appropriate decision-maker.

95. In relation to the AoB charge, Meridian agrees with the Read Report that the Authority should, for example, stipulate in the guidelines:

- Basic guidance about what the concepts of "area" and "benefit" entail.

- The purpose of the AoB charge, namely, to recover asset costs in proportion to the net positive benefits customers are (or were) expected to receive, as determined by ex ante runs of an optimisation model under one or more scenarios.

- How capital expenditure is to be divided into assets and investments.

- The existing assets to which the AoB charge is to apply (as discussed in relation to refinement #1).

- That charges for historic assets are to be based on the presently unrecovered costs as per the RAB values (as discussed in relation to refinement #4).

96. These are all issues of economic principle where the Authority has the appropriate information, capability and incentives to make the final decision. They are not implementation or technical issues that would be better left to Transpower.

97. In terms of the HVDC issues discussed above, Transpower "will be less concerned about how [its regulated revenue] is made up (between AoB and the residual) than the Authority will be".[76] Transpower itself has commented that "the question of whether South Island generators should continue to pay any or all of the costs of the HVDC link appears to primarily be an equity / durability one that the Authority is best placed to address".[77] It has also expressed firm views including that a "time neutral" approach should be adopted,[78] which would presumably involve revaluing old assets and ignoring depreciation that has already been recovered by Transpower.

98. If such objectives and decisions are not stipulated in the guidelines now, the risk is that Transpower will produce a TPM that is very different from what is currently intended – but not specified clearly enough. For example, Transpower has proposed its own "simplified" methodology which appears to operate like a regional postage stamp. The Authority rightly notes that this would not be an acceptable solution,[79] but the guidelines themselves are not drafted in a way that makes it clear that such a proposal is excluded.

99. Furthermore, it will greatly complicate Transpower's consultation process and timeframes if these matters are not settled by the guidelines. Meridian doubts that it will be feasible for the TPM to be finalised within a reasonable period if these big picture issues remain open: many aspects of the Authority's consultation will need to be re-run before decisions can be made which allow the TPM itself to be drafted. In addition, if the Authority does not clarify the guidelines now, this will only cause delay later on in the TPM review process if the Authority reaches a different view on the TPM as proposed, when it is provided back to the Authority for final approval.

100. Conversely, we are concerned that some of the detail in the draft guidelines may prevent Transpower from developing an optimal implementation strategy. For example, the stipulation for standard and simplified methodologies unnecessarily constrains development of the TPM and may not allow optimal solutions to be developed. The $5m distinction is essentially arbitrary and its application will depend on how assets are grouped into investments. We consider the methodologies should be developed by Transpower in forming the TPM. The only steer the Authority needs to give it in the guidelines in this respect may be to set out the principle that it is appropriate that more modelling effort is given to assessing benefits for larger investments.

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76 NERA Report at [111(b)].

77 Transpower *Submission: Transmission pricing methodology, 2nd issues and proposals paper* (26 July 2016) at p 9.

78 Transpower *Submission: Transmission pricing methodology, 2nd issues and proposals paper* (26 July 2016) at p 19.

79 In its "Questions and Responses" website, available at: <http://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/development/questions-and-responses/>.

101. We consider that further work in redrafting the guidelines in the manner indicated above is required before the TPM review proceeds to the development stage. We do not consider that this requires further consultation but it is important that the guidelines are clear and unambiguous, and set an appropriate balance between locking-in key principles and giving Transpower flexibility in terms of how they are implemented.

5. The residual charge, the charges for overheads and unallocated costs, and AoB charges for pre-guideline investments may need adjustment

102. The Authority has proposed that Transpower put forward a method for scaling back charges to deal with the possibility that the method for determining the annual amount recovered under the AoB charge for pre-guideline investments results in over-recovery of Transpower's recoverable revenue.[80]

103. The proposal is to deal with situations where:

(i) Transpower uses a high proxy value for a pre-guidelines eligible investment because it cannot determine the cost of that investment;[81] and / or

(ii) Use of IHC or replacement cost rather than DHC values produces high values.[82]

104. As discussed in relation to refinements #1 and #4 above, Meridian is strongly opposed to new charges being set for pre-guideline investments in a way that fails to properly assess beneficiaries and/or disregards depreciation funded to date. The fact that refinement #4 in particular creates a need for a related refinement introducing a methodology to cover the risk that the AoB charges for the 11 currently eligible historic assets (along with any others that Transpower adds in the exercise of its discretion) could on their own exceed Transpower's MAR highlights the problems with refinement #4. If the Authority accepts Meridian's submission on refinement #4, then the need for this refinement #5 will largely be avoided.

105. However, assuming that levelled charges (either for new assets or for old assets based on the remaining revenue to be collected given depreciation to date) continue to be part of the Authority's proposal, the amount collected for a particular asset in a particular year will be more (for older assets) or less (for newer assets) than the recoverable revenue implied by the RAB value. Accordingly, there may still be a need for an adjustment mechanism and Meridian supports refinement #5 on this more limited basis.

6. Optimisation available only for high value investments

106. The combination of refinements #1 and #4 above raise the possibility that a party may be one of a limited number of "deemed beneficiaries" or "pseudo-residual charge payers" across a relatively large number of heavily depreciated historic assets that have been significantly revalued under the IHC approach. Meridian considers that optimisation should potentially be available in these circumstances and for this reason does not support this refinement as currently framed.

80 Refinements Paper at [3.70].
81 Refinements Paper at [3.69], [3.73], and [3.74].
82 Refinements Paper at [3.73] and [3.74].

7. Should the fall-back method for allocating the AoB charge to generation be lagged or forecast injection?

107. For the reasons given by NERA in its report on the Second Issues Paper,[83] Meridian submits that the best method to use as a fall-back for allocating the AoB charge to generation is forecast average injection. However, that was in the context of a fall-back method that was only potentially applicable to new assets valued at less than $5million for which there would be good cost information. Meridian does not support the use of a fall-back method to allocate the costs of significantly more valuable historic assets for which there is no good cost information. Such assets should fall into the residual.

8. An additional component to align the method for charging for connection assets with the method for charging for AoB assets

108. The Authority has proposed allowing Transpower to align the method for determining the annual amount to be recovered in connection charges for each asset with the method for AoB assets, if practicable and consistent with clause 12.89 of the Code.

109. In Meridian's view, the current method for charging for connection assets has some features that are not fully cost-reflective. Connection charges take into account the depreciation of all connection assets and then allocate that according to the relative replacement cost of the particular asset versus all connection assets. Accordingly, charges are smoothed, but not level, and an NPV=0 return occurs across the pool, but not necessarily for any particular connection asset.

110. That said, participants have not raised practical problems with the connection charge. Given our view that issues of asset valuation and annual revenue to be recovered should be matters for the Authority and the well advanced stage of this consultation, Meridian supports the status quo remaining in place in terms of the method for charging for connection assets.

9. The marginal price adjustment for a new investment to be an additional component

111. Meridian supports the Authority's proposed refinements to treat the marginal price adjustment as an additional component and to limit its application to cases where the action committed to by the customer would result in a decrease in Transpower's costs.

10. Transpower must seek to make a more specific allocation to the connection and AoB charges of overhead and unallocated expenses

112. Meridian understands the desire to further allocate overhead and unallocated expenses to beneficiaries, to the extent practicable. However, any allocation of overheads must be done on a principled basis. Transpower should not seek to allocate true common costs to individual assets. This proposed refinement risks "Transpower arbitrarily allocat[ing] costs to specific investments, reducing cost and service reflectivity, and reducing the durability of the TPM."[84] Meridian agrees with

83 NERA Economic Consulting *Transmission pricing methodology – review of second issues paper* (26 July 2016) at pp 12-13.

84 NERA Report at [12(b)] and [80].

NERA that in this regard the proposed refinement “is odd – if the relevant costs could be allocated to specific investments, then why has that not already been done?”[85]

113. The Authority’s draft guidelines provide that Transpower’s overhead and other expenses are to be allocated to each asset if they “relate to” a qualifying asset.[86] In Meridian’s view the broad drafting of this proposed refinement risks allocating common costs to individual assets. NERA has reached the same conclusion, and is concerned that allocating truly common costs to a new investment “would distort decision-making about that investment”, which would undermine scrutiny benefits and would lead to under-investment in the grid.[87]

114. Meridian recommends that the guidelines be amended to mitigate this risk. Various drafting options are available for this purpose. The Authority could:

- Redraft the relevant provisions of the guidelines to provide that Transpower may only allocate costs to a specific asset if those costs are “directly attributable” to that asset. As NERA points out, this would be consistent with the language adopted by the Commerce Commission in its cost allocation IMs across several sectors including EDBs.[88]

- Make explicit that Transpower is not to seek to allocate common costs to individual assets, together with a definition of common costs.

- Provide non-exhaustive examples of such costs.

115. Furthermore, if this refinement is adopted, Meridian considers that the Authority should revisit its proposal in the Second Issues Paper to allocate some of the overhead and unallocated expenses onto the connection charge.[89]

116. If the refinement is adopted then only common costs should remain and there is no longer any basis for the allocation to the connection charge. Nor did Meridian support the Authority’s proposal in this regard, as the Authority suggests.[90] Meridian does not support charging generation for these costs through the connection charge. As the Authority accepts, a firm in a workably competitive market would seek to recover common costs from charges to those customers whose behaviour would be least affected by the charges.[91] Meridian continue to support NERA’s economic analysis that the least distortionary way to recover these expenses is to allocate them 100 per cent through the residual charge, which should be recovered from load.[92]

11. The load of each customer is to be used to identify who is liable for the residual

117. Meridian agrees that the load of each customer without netting off generation should be used to identify who is liable for the residual charge and the extent to which those customers must pay.

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85 NERA Report at [79].
86 Clauses 5(a)(ii) and 6(b).
87 NERA Report at [80].
88 NERA Report at [13(b)] and [81].
89 Second Issues Paper at [7.208].
90 Refinements Paper at [3.103] and fn 64.
91 Refinements Paper at [3.103].
92 NERA Economic Consulting *Transmission pricing methodology – review of second issues paper* (26 July 2016) at pp 14-18 and 22; Meridian Energy *Submission Transmission Pricing Methodology: Issues and proposal: Second issues paper* (26 July 2016) at p 43.

12. The calculation of the residual charge, and if necessary the AoB charge for load, must follow principles and be less prescriptive

118. Meridian agrees that not prescribing a particular capacity measurement approach, and providing for Transpower to propose an approach to the Authority according to a set of principles, has merit. It also supports the proposed set of principles set out at [3.123] of the Refinements paper. They are worded broadly enough to address Meridian's concerns that:[93]

- An appropriate allocator should minimise distortions in customer behaviour;
- The same allocator should be used for both direct connect customers and distributors.

119. As noted in relation to refinement #1, however, the AoB charge for historic assets should always be based on a proper assessment of benefits. Otherwise they should be recovered through the residual.

13. Calculation of the residual to avoid double counting and other anomalies

120. Meridian supports the guidelines providing that calculation of the residual charge must seek to avoid double counting and other charging anomalies, and result in broadly equivalent charges to customers that are in broadly equivalent circumstances.

14. The AoB and residual charge of a large consumer to be tied to the consumer

121. For the reasons given in the Refinements Paper Meridian supports the Authority's proposal that if a large consumer changes supplier, the consumer's AoB and residual charges it paid to the original supplier would shift with it in the manner described by the Authority.

15. If an LRMC charge is applied, the TPM must specify a method to adjust other charges

122. The Authority's proposal is that the guidelines provide that: (1) an LRMC charge must complement or augment but not duplicate price signals provided by nodal pricing, other transmission charges, and any grid support arrangements relied on by Transpower to efficiently defer transmission investment; and (2) an LRMC charge may only be included if a price signal is required over and above the price signals provided by those listed above.

123. Meridian agrees with the expanded scope of existing price signals that are to be considered. It also supports the requirement that TPM charges should be adjusted if an LRMC charge is introduced. It would not be efficient for an LRMC charge to be considered in isolation from other price signal sources that will already be available in the proposed TPM.

93 Meridian Energy *Submission Transmission Pricing Methodology: Issues and proposal: Second issues paper* (26 July 2016) at pp 39-40 (section 21.3).

124. Meridian agrees with the economic analysis provided by NERA that "any revenue raised through a LRMC charge should be offset by reduced AoB charges."[94] Even though the LRMC charge would respond to current congestion, it also pre-funds future assets, but in any case it will be difficult to draw such a distinction. Regardless, the double-charging concern still applies to existing assets (as where an existing asset is subject to AoB charges but also to LRMC charges), resulting in over-recovery for that asset. Meridian therefore supports NERA's conclusion that LRMC charges should be offset by reduced AoB charges.[95]

16. The PDP would not apply to inefficient exit

125. Meridian considers that the rationale for the extension of the PDP to prevent inefficient exit is economically sound,[96] is likely to have material benefits,[97] and that risks of gaming/asymmetry can be addressed through the design rules and application of the policy. Meridian agrees with NERA that it is "too early to definitively exclude the "inefficient exit" component of the PDP, and this is an issue in respect of which … Transpower is well-placed to do some further analysis".[98] For this reason Meridian does not support the removal of the PDP where it would prevent inefficient exit.

17. Maintaining competitive neutrality between grid connected generation, DG and DR

126. Meridian supports the principle that the TPM be directed at facilitating competitive neutrality between grid connected generation, DG and DR. However, if the principle is listed, then it raises the question of what other relevant principles should be in the guidelines. As discussed in relation to refinement #4, Meridian supports a clearer articulation of the objectives of the new TPM and its various components.

18. Cap on transmission charges

127. In its Refinements Paper the Authority proposes the introduction of "a price cap on transmission charges".[99]

128. Meridian considers that a price cap will slow the introduction of cost-reflective and service-based charges. Further, the shortfall in revenue that arises when charges are capped for one customer means that other customers will pay more as a result. As NERA states, "A price cap has the potential to undermine grid price signals".[100]

129. However, Meridian acknowledges that a price cap may be appropriate for pragmatic reasons to smooth potential price jumps if it applies for a limited time and there is a clear path from capped to uncapped charges.

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94 NERA Report at [89].
95 See NERA Report at section 3.4.1.
96 Second Issues Paper at [7.227]-[7.260]; Meridian Energy *Submission Transmission Pricing Methodology: Issues and proposal: Second issues paper* (26 July 2016) at pp 40-42; NERA Economic Consulting *Transmission pricing methodology – review of second issues paper* (26 July 2016) at pp 21-22; NERA Report at [94].
97 NERA Report at [95].
98 NERA Report at [13(d)] and [96].
99 Refinements Paper at [3.179].
100 NERA Report at [101].

130. Meridian has a number of specific concerns about the particular price cap proposed by the Authority. These include:

- The amount of the cap is subject to many exceptions and extensions. For instance, the cap will continue to rise by 2% per annum for direct consumers only; charges are to be set using incremental cost in certain circumstances; Transpower can increase the cap by reference to an increase in a customer's load; and the cap can increase for all customers so that Transpower recovers its MAR. These distinctions make it difficult to understand the purpose and likely operation of the cap in practice.

- Inclusion of distribution charges, energy charges and tax in the "base value" effectively indemnifies consumers against a variety of potential cost increases (such as a rise in GST) that are unrelated to transmission charges.

- No transition path nor expiry period is clearly discernible.

131. These concerns are partly conceptual and partly about the drafting. Meridian considers that, if there is to be a cap, then the guidelines should clearly articulate the governing principles, with Transpower to develop the implementation detail as part of the TPM process. For example, the Authority should specify in the guidelines only:

- That the TPM will contain a price cap;

- A clear statement of the purpose(s) of introducing a price cap and what charges it applies to; and

- A clear transition path and expiry period for that price cap.

APPENDIX 1: QUANTIFYING THE IMPACT OF OVER-RECOVERY ON STYLISED HVDC ASSETS FROM A POTENTIAL CHANGE FROM DHC TO IHC CHARGING

HVDC charging

1. As part of the Transmission Pricing Methodology review the EA is considering changing the manner in which the HVDC (and other) assets are valued over time.

2. Currently a portion of the HVDC charge reflects historically invested capital, with charges determined by a straight-line reducing balance depreciation approach applied to the book value of the asset, ie the depreciated historic cost approach (DHC).

3. The EA considers that an alternative to this may be better aligned to asset market value, usage and subsequent benefits. This approach is reflected by an amortised capital cost approach (ie similar to a table mortgage), the indexed historic cost approach (IHC) – applied retrospectively regardless of monies paid to date.

4. Here we seek to quantify the impacts of such a potential change from DHC to IHC in asset valuation on illustrative HVDC charges for the market.

Stylised charging example

5. Calculating the actual increase in payments would require a complex reconciliation of book values, changes to WACC, EVA accounting, under-recovery of costs, asset lifetime, class of asset, and other variables. Many of these real world factors can be difficult to fully reconcile with available and often contradictory invoice data and some of these factors (e.g. nominal versus real) may exacerbate the impacts discussed.

6. To provide an estimate based on currently available data, we more generically consider two stylised HVDC assets that are intended as an approximation of Pole 2 and Pole 3:
    - In 2017 money
    - Using a real WACC of 5.4%[101]
    - One asset commissioned in 1992 with a 40 year life time at a cost of $750M (in 2017 money)
    - Another asset commissioned in 2013 with a 40 year life time at a cost of $750M (in 2017 money).

7. In the remainder of this appendix we examine briefly what a change in charging methodology might mean for market participants:
    - As at 2017; and
    - Over the next few decades.

8. The purpose is to estimate the extent of over-recovery of costs.

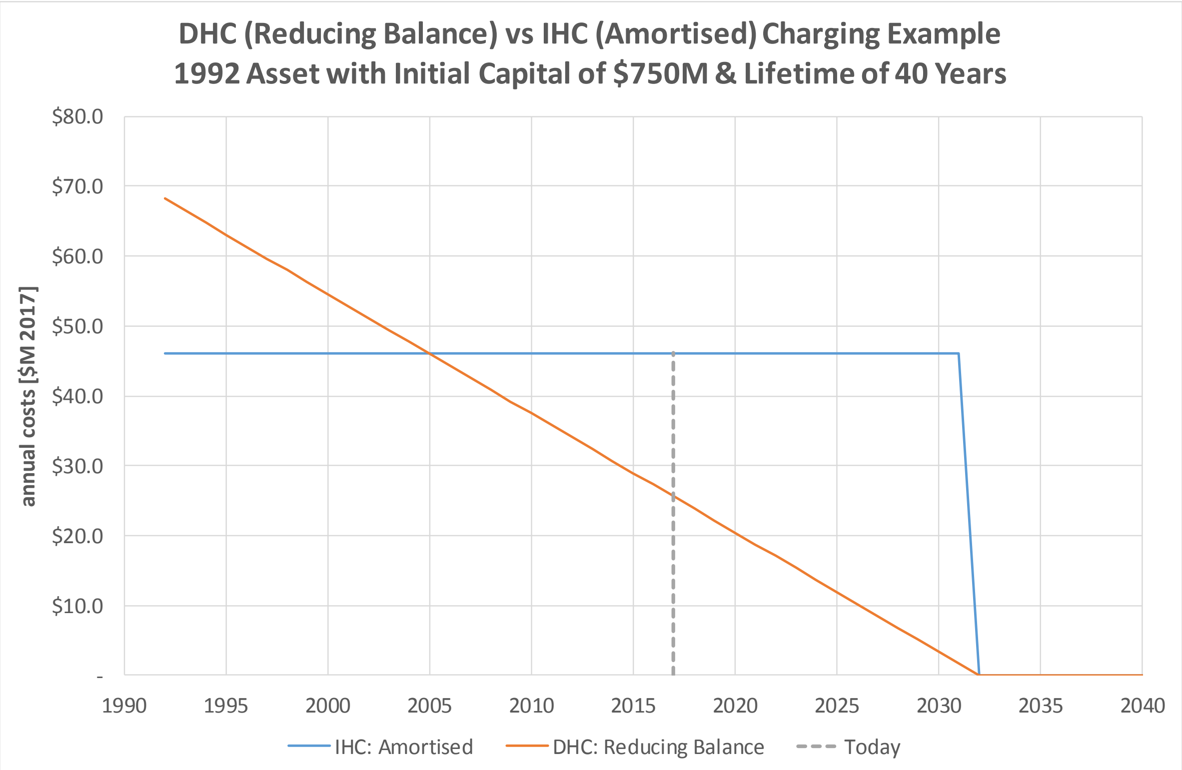
[101] Equivalent to a nominal WACC of 7.4% and inflation of 2%.

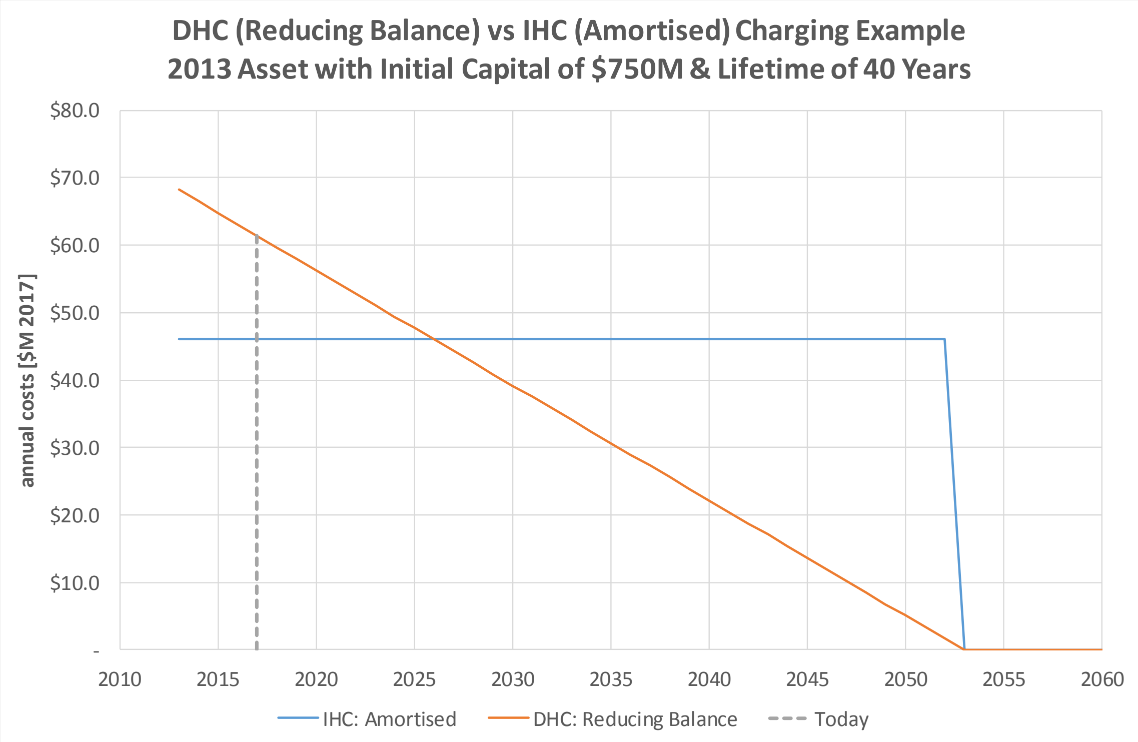
DHC versus IHC compared

9. The DHC approach assumed represents a simple reducing balance approach:
    - BV y1 = C … for year 1
    - BV yt = BV y(t-1) – C/L … for year 2+
    - DHC yt = BV yt.(w+d)
        - BV = book value, C = initial capital
        - L = lifetime
        - w = WACC
        - d = depreciation adjustment
        - y = year, t = time

10. The IHC approach assumed represents a simple amortisation/payment approach:
    - $IHC_{yt} = C.w/(1-(1+w)^{-L})$
        - C = initial capital
        - L = lifetime
        - w = WACC
        - y = year, t = time
    - This represents a simple geometric series sum.
    - No additional adjustment for depreciation tax shield, inflation, etc…

11. The following charts represent the effect of DHC and IHC charging for the 1992 and 2013 assets respectively:





12. The present value (DCF using WACC) of the two approaches is identical and returns the initial capital invested.

2017 charging

13. We can see from contrasting these two approaches:

- Older assets experience an increase in charges since the pivot point of equal cost charges is in the past.
- Newer assets experience a decrease in charges since the pivot point of equal cost charges has not yet been reached.
- The pivot point (for this WACC and asset lifetime combination) in both cases occurs at about year 14.

14. For our example, as at 2017 this would mean an overall increase in capital charges recovered by $5M:

2017: DHC (Reducing Balance) vs IHC (Amortised) Charging Example			
	DHC	IHC	delta
Asset 1992	$ 26	$ 46	$ 21
Asset 2013	$ 61	$ 46	-$ 15
Total	$ 87	$ 92	$ 5

15. This divergence in charging will grow over time as we move towards the later years of the respective asset lives.

16. Without any further adjustment an over-recovery of the initial capital deployed will occur.

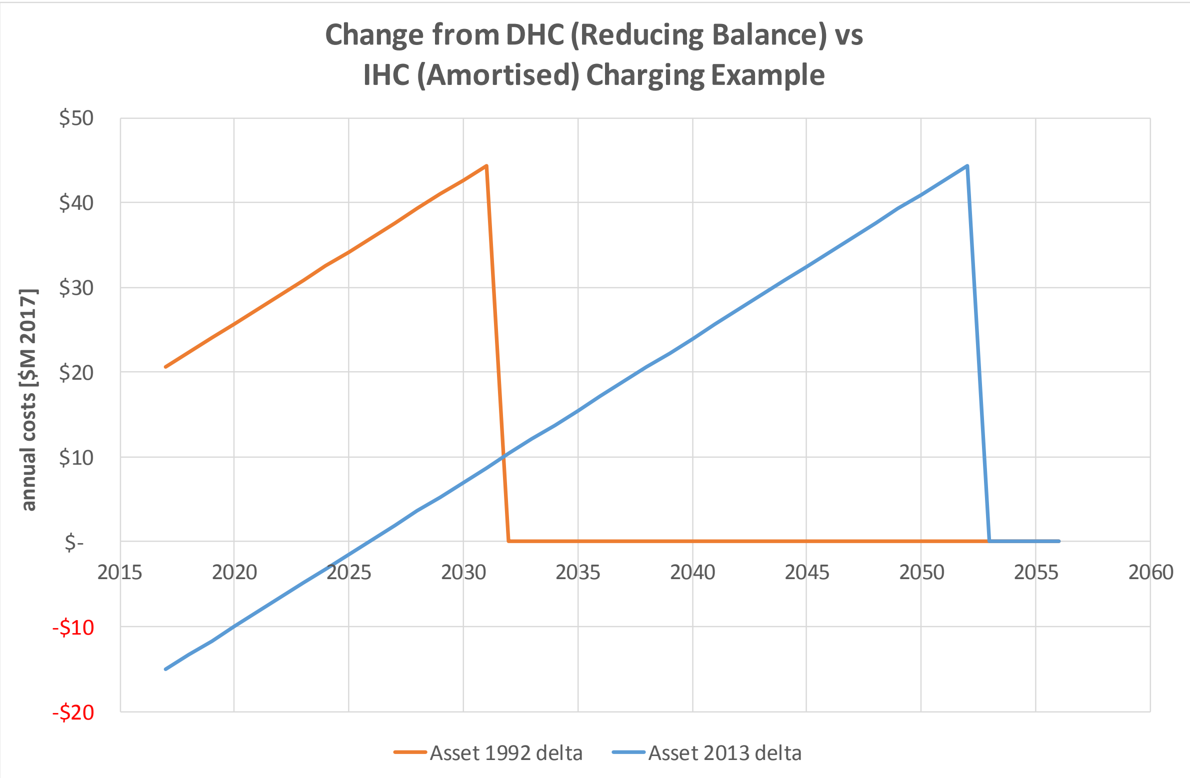
17. In addition to this, if the IHC approach uses a longer asset life estimate then the capital over-recovery potential will grow further.

Change in charging – future decades

18. The change in charging implied by the new IHC methodology will increase over time, in our example:
    - By up to $45M in 2031 for the 1992 asset; and
    - By up to $45M in 2052 for the 2013 asset.

19. In terms of money recovered this means that as at 2017 if changes were made to the charging methodology then:
    - An additional $490M of charges are recovered for the 1992 asset ($310M in Discounted Cash Flow (DCF) terms as at 2017).
    - An additional $525M of charges are recovered for the 2013 asset ($85M in DCF terms as at 2017).

20. These charges represent additional revenue above and beyond the initial capital outlay; i.e. this is an <u>over-recovery</u> of capital spent:



Over-recovery of capital increases if asset life is extended

21. Suppose the asset life for the 1992 asset is extended by 10 years in 2017 (i.e. 40 years to 50 years).

22. This would drop the blue line by about 5% so that the total collected in DCF terms over the extended asset life remains the same - say from $46m pa to $43.5m pa.

23. So between 2017 and 2031 over-recovery will drop by $2.5m x 15 years = $37m.

24. But there is now an additional 10 years (2032–2041) of charges, so $435m more over the life of the asset.

25. This would be a net increase of $400m, or in DCF terms as at 2017 $125m of present value.

26. A similar logic applied to the 2013 asset would add a further $350M of additional net IHC charges, or in DCF terms as at 2017 $10M of present value.

Meridian charges to date

27. We now briefly examine actual rather than hypothetical HVDC charges.

28. Meridian’s share of costs has historically represented 70-75% of total HVDC charges:
    - Loss of Tekapo power stations altered this balance in 2011.
    - Market is currently in process of changing from HAMI (MW) to SIMI (energy) cost allocation.

29. Over the last 19 years and including the 2017 pricing year Meridian has paid $1.5B (in 2017 money) in HVDC charges:
    - Of this approximately $1B (being two-thirds) of these costs are directly attributable to recovery of capital.
    - Over the same period total HVDC charges have totalled $2.2B (real).

30. The table below illustrates Meridian’s HVDC charges in nominal and real terms:

pricing year	HVDC Charges MEL Accounts				
	Actual Charge (nom)	Total (real)	implied		
			capital (nom)	under recovery (nom)	other (nom)
1999	$ 61	$ 89	$ 53	$ -	$ 8
2000	$ 55	$ 79	$ 49	$ -	$ 6
2001	$ 47	$ 66	$ 40	$ -	$ 7
2002	$ 46	$ 62	$ 37	$ -	$ 9
2003	$ 47	$ 62	$ 36	$ -	$ 11
2004	$ 49	$ 64	$ 35	$ -	$ 14
2005	$ 57	$ 72	$ 42	$ -	$ 15
2006	$ 61	$ 74	$ 43	$ -	$ 17
2007	$ 68	$ 81	$ 50	$ -	$ 17
2008	$ 61	$ 70	$ 43	$ -	$ 18
2009	$ 58	$ 65	$ 37	$ -	$ 21
2010	$ 62	$ 68	$ 34	$ -	$ 28
2011	$ 86	$ 90	$ 50	$ 9	$ 27
2012	$ 88	$ 92	$ 46	$ 17	$ 25
2013	$ 111	$ 115	$ 69	$ 17	$ 26
2014	$ 100	$ 102	$ 57	$ 17	$ 26
2015	$ 104	$ 106	$ 60	$ 17	$ 27
2016	$ 106	$ 108	$ 62	$ 17	$ 27
2017	$ 104	$ 104	$ 60	$ 17	$ 27
Total	**$ 1,368**	**$ 1,569**	**$ 903**	**$ 111**	**$ 354**