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Submissions
Electricity Authority
PO Box 10041
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By email: submissions@ea.govt.nz

Re: Consultation Paper – Transmission pricing review

Nova Energy appreciates the opportunity to review the extensive consultation paper and supporting documents for the 2019 Transmission pricing review.

Overall the proposed TPM more accurately reflects the cost of delivering energy to end consumers over time. Given that it reduces disincentives to utilising the available grid capacity, it should help reduce inefficient investment in transmission avoidance strategies.

It is of concern however that the Authority proposes fixing the allocation of charges over the long term, with little flexibility built in to respond to changing generation and demand patterns. The pendulum is being swung too far from peak demand pricing, to the extent that charges are likely to become inequitable and economically inefficient over time. Thus, as with the existing methodology, a new set of winners and losers will be created.

Nova makes some suggestions in the attached appendix addressing its reservations on the proposed TPM. Key points are as follows:

1. The nodal pricing signal should be strengthened. If this is done, then a peak pricing regime should not be necessary. This can be achieved by adding an additional losses equation for each circuit in SPD as part of the RTP project.
2. The AoB charge should be reset on a rolling 4-5 year basis, thereby taking into account changes in generation and demand over time.
3. The AoB charge should be based on net demand, excepting that embedded generation exports of over 10MW should be included.
4. It would be totally inappropriate to include 'behind-the-meter' demand in determining the residual charge. If the residual charge is to be based on gross demand, then that should be determined from reconciliation data only.
5. The residual charge should be based on a simple mix of RCPD, AMD and kWh demand. With the right parameters, this would adequately dilute the peak charge signal such that the pricing would be responsive to shifting net load patterns over time, without over-incentivising inefficient investment.
6. The TPM as proposed is going to add significant unrecoverable costs to Nova and its associated parties through the AOB charges on generation. It would be inappropriate to increase the impact of that by asking North Island generators to also contribute to covering the price cap on load customers.

The Authority is aware that there is no 'right answer' for transmission pricing as it is purely an allocation mechanism. The solution now proposed has advanced from earlier proposals but is overly complex in attempting to cover against any cost minimisation by market participants. Nova suggests further refinement and some simplification is required before it is implemented.

Please feel free to contact me if you wish to discuss our views further.

Yours sincerely

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Nova submission

2019 Issues Paper - Transmission Pricing Review Consultation Paper

Q No.	Question	Response
	Chapter 2	
1.	Have the problems with the current TPM been correctly identified? In what ways does the current TPM work well?	The strength of the current TPM has been: • its simplicity, • the dynamic response to changing demand patterns, and • it reflects the use of the Grid. The problems are correctly identified.
	Chapter 3	
2.	What are your overall views on the Authority's proposal for changes to the TPM guidelines?	Overall the proposal more accurately reflects the cost of delivering energy to end consumers over time. Given that it reduces the penalties on peak demand, it should help reduce inefficient investment in avoidance strategies and support greater use of the grid. The inflexibility of the proposed determination of the beneficiaries of benefit-based investments is problematic, however. While there is validity in ensuring there is no inefficient avoidance of charges, the method of locking charges in is punitive in that it potentially imposes unrecoverable costs to market participants as a result of valid commercial decisions. While the methodology is designed to prevent avoidance, it also needs flexibility to reflect changes in demand patterns once the new TPM comes into effect. I.e. in the absence of an RCPD demand and subsequent responses by EDBs in respect of load control, and consumption, the AoB for grid investments are likely to shift from the time period over which the charges have been determined. This is in addition to the more obvious additions and reductions in generation capacity over time.

Q No.	Question	Response
	Chapter 4	
3.	Does the CBA provide a reasonable estimate of the costs and benefits of the proposal? If not, what changes to the methodology and / or assumptions would improve the estimate?	
4.	Do you have any comments on the matters covered in chapter 4?	
	Chapter 5	
	Refer Questions 66-70.	
	Chapter 6	
5.	How long should Transpower have to complete its development of the TPM and why?	Nova believes a minimum of two years, and a maximum of three years is appropriate. There are parts of the TPM implementation that Transpower should still consult on and provide time for constructive input and feedback in the process. There also needs to be enough lead time for EDBs to factor the new charges into their pricing regimes.
6.	What checkpoints (if any) should the Authority set in the TPM development process?	Transpower should be able to develop and consult on each of the charging elements separately in order to spread resources both internally and with market participants. Each element should be consulted on with participants and approved by the Authority.
7.	How should Transpower best engage with its stakeholders during its development of the TPM and how regularly should that engagement occur?	That really depends on each element of the TPM. The Connection Charges, for instance, can probably be resolved reasonably quickly.
8.	In addition to the specific questions	

Q No.	Question	Response
	above, do you have any further comments on the matters covered in chapter 6?	
	Appendix A	
9.	What are your comments on the drafting of the proposed guidelines? Are any aspects unclear or unworkable? Do the guidelines clearly convey the policy set out in appendix B?	An area of significant concern is the allocation of charges to parties that add or remove generation or load from the grid. While we accept the need to avoid uneconomic disconnection, or subsidies for new entities, rules in this area should not penalise sound commercial decisions such as: • when parties invest in a particular location because of a need for a higher degree of security of supply than can be delivered by the transmission and distribution networks, or • situations where uneconomic generation or load would be withdrawn from service, except that transmission charges are ongoing and need to be recovered. Consideration also needs to be given to the fact that changes in generation capacity can occur in an incremental manner, such as: upgrades of hydro capacity, which generally occurs one turbine at a time, or changes to a windfarm's capacity, which can may include a upgrade, or even shut-down one turbine at a time. Over just a few years the AoB charge could become disproportionate to the actual benefit being accrued to the generator. It is important for any investment in new generation that the expected revenues, costs, and risks are quantified as accurately as can be achieved in the circumstances. Creating a situation where it is uncertain when and what grid charges might be imposed on a project adds to uncertainty and will likely delay new investment. Similarly, in a time of technological change, with expect growth in Solar PV and Electric Vehicles, the consumer benefit of grid upgrades will shift significantly as the uptake of the newer technologies in lower socio-economic regions are likely to be

Q No.	Question	Response
		markedly slower than in more affluent regions.
	Appendix B	
	General matters	
10.	Do these provisions give Transpower sufficient flexibility to develop the TPM while ensuring that the intent of the guidelines is followed and that the interests of designated transmission customers are protected?	The stand-out exception in the Guidelines is the specific inclusion of Schedule 1. While the Authority may have valid reasoning for its workings etc. in preparing Schedule 1, there should still be scope for Transpower to rework those numbers. There also needs to be a clear mandate defining how and when those numbers will be updated. As stated above; between the time used to calculate those factors and the implementation of the TPM there are expected to be a number of new generators, potentially some shut-downs, and possible significant changes in load. The pricing needs to be more dynamic than that proposed by the Authority.
	Connection charge	
11.	Should the current guidelines on connection charges be largely retained or are changes required?	Largely retained.
12.	Should first-mover disadvantage be addressed in the TPM, and if so, how?	Yes. A party connecting to the Grid should be charged on the basis of the optimal asset structure required to meet the needs of the connected party only. Transpower should also be free to choose whether at the same time additional connection assets or capacity should be added for the long term benefit of market participants. That could include elements such as provision of additional space in switchyards, additional security elements or upgrading aging equipment. All those things could be optimal decisions given the information available. Such investments, however, should not be attributed to the new connecting party. Nova has direct experience of where Transpower wants to specify connection

Q No.	Question	Response
		design and assets that are more to do with enhancing grid flexibility and security than they are with the specific requirements of a new connection. Enhancements that are made in addition to the optimised grid connection should be recovered though the residual charge.
	Benefit-based charge	
13.	Do you think introducing a benefit-based charge for future grid investments will promote efficiency and the long-term benefit of consumers?	Yes.
14.	Should the cost of pre-2019 investments be recovered in some other manner than through the residual charge, and if so how? Which pre-2019 investments should be recovered in this manner? In particular, do you consider that the cost of some past investments should be recovered through a benefit-based charge?	Yes. While in principle, Nova generally disagrees with imposing new charges on pre-committed investments, in this case shifting the weighting of charges from the residual charge to the AoB charge can be expected to lead to more efficient use of the grid, i.e. reducing the focus on minimising peak demand and a more cost reflective regional allocation. A feature of the New Zealand grid, in comparison with many electricity grids internationally is that it is not so much a grid, as a north-south (and vice versa) transport link. As such, it has generally been reasonably clear when new grid investments have been made where the benefitting parties would be located. Another factor is that those parties benefitting from those investments have partially had a free ride to date. Extending that into the new pricing regime does not justify a perpetual subsidy through spreading the costs through the residual charge.
15.	Assuming that a benefit-based charge is to apply to at least some pre-2019 investments, to which such investments should it apply?	The AoB charge should be applied to all the major investments identified, including the Otahuhu Diversity upgrade. While the Otahuhu Diversity upgrade may not be reflected in benefits through energy prices, the project was clearly aimed specifically at improving the security of supply for load in Auckland and Northland. The decision to invest in the upgrade was made at a political level driven by Auckland imperatives. Auckland and Northland should be charged for a large proportion of that upgrade even if the

Q No.	Question	Response
		benefits are reflected in a greater security of supply rather than lower nodal prices, as calculated by the vSPD modelling.
16.	How should the covered cost of the investment be defined?	
17.	How should the covered cost of a benefit-based investment be recovered over time for pre-2019 investments and post-2019 investments? How much discretion should Transpower have to determine the method?	
18.	Should the guidelines require Transpower to adopt a net load or a gross load approach in determining customer benefits, or should flexibility be allowed?	Nova believes that Transpower should be required to adopt a net load approach; excepting that embedded generation over 10MW not directly associated with industrial load (i.e. excluding co-generation plants) should be grossed up as a measure to prevent cost avoidance or cross subsidies. Under a beneficiary pays approach, load customers should not stand to gain from significant independent generation connected behind the GXP.
19.	Should the guidelines distinguish between high-value and low-value investments?	
20.	If so, should the costs of low-value investments be allocated via the residual charge or via the benefit-based charge using a simple method?	
21.	What is an appropriate threshold between low-value investments and high-value investments? Does it depend on whether the cost of low-value investments is recovered through the benefit-based charge?	

Q No.	Question	Response
22.	What are your views on the Authority's proposal to determine a benefit allocation for seven major existing investments (including the proposed and alternative methods)?	Nova favours including the seven major existing investments plus allocate the additional three major investments not included in the proposal to load customers based on the enhanced security benefits they provide.
23.	How should the costs of the investments that are not covered by the benefit-based charge be allocated?	Nova favours the bespoke methods described in B.148, as the alternative has parties who gain no benefit from those investment whatsoever paying for them. Further comment is provided in response to Q15.
24.	Should charges be revised if there has been a substantial and sustained change in grid use? If so, what threshold would be appropriate to define such an event?	Yes, the charges do need to be reflective of changing circumstances, otherwise decisions will be made in the expectation of there being no change in cost. New technologies can be expected to shift electricity supply and demand patterns quite significantly over time, or major investment (or divestment) decisions may result in large step changes. If the benefit charges were recalculated on a rolling basis (using 5-years of data) annually, then a change in charges for any one connection (say 10%?) should trigger a re-weighting of charges for at least that connection. This would capture changes such as a pot-line shutdown or start-up at Tiwai, or cement plant closure in Buller.
25.	Should the implementation of the charges for low-value post-2019 investments be deferred, and if so, for how long?	Only to the extent to which priority needs to be given to applying the benefit charge on the large investments.
26.	Should the guidelines allow for reassignment of costs from the benefit-based charge to the residual charge? What are your views on the proposed reassignment provisions?	Yes. There needs to be facility for this where it would be unreasonable to continue to charge for generation or load that no longer exists. If there is concern that a grid investment was made specifically in response to a new load or generation, then it should be possible for Transpower to contract for recovery of a certain level of that invest from the responsible party. The quid pro quo of that would also logically result in the paying party receiving Financial Transmission Rights over the section of line being upgraded.

Q No.	Question	Response
	Residual charge	
27.	Should the guidelines provide for a single residual charge or multiple residual charges?	Provision should be made to allow Transpower to use more than one allocation method if it can see merit in doing so. A number of simple allocation rules may be less complex than a single rule trying to cover all scenarios.
28.	Should any remaining MAR be recovered through a fixed residual charge? Should the residual charge be allocated based on a customer's historical electricity demand?	
29.	Should the residual charge be allocated based on AMD, annual consumption, a mixed approach, or some other approach?	It would seem that using a combination of relatively simple approaches, e.g. AMD, RCPD, and MWh allocation would capture most situations and be consistent with keeping the incentives to inefficient avoidance of the charges to a minimum. The weighting applied to each element could be linked to specific cost elements, e.g. overheads on a MWh basis, or simply a pro-rata weighting of each approach.
30.	If the residual charge is to be allocated based on AMD, how should multiple points of connection be treated?	The 'non-coincident peak' method would seem to be preferable as that ensures that larger EDBs with multiple NSPs do not receive a cost advantage over EDBs with just a few NSPs.
31.	Should demand be measured using a net load or gross load approach for the allocation of the residual charge?	Nova proposes adopting a net load approach, subject to including any generation exports of over 10MW from embedded generation. Smaller embedded generation and behind-the-meter demand should not be included as there is little economic advantage in doing so. It also helps avoid a situation where parties are incentivised to locate generation behind-the-meter. The problem with including behind-the-meter load is that it includes more load than would ever be load on the grid or distribution network from that source, i.e. where the electricity demand only occurs when embedded generation is running, and not at other times. Dairy factories and the Kapuni Gas Treatment Plant are examples that require simultaneous supply of steam and electricity. These sites therefore do not have the same levels of electricity demand in the absence of the co-generation

Q No.	Question	Response
		plant running. Similarly, a hydrogen production facility may be in operation in the future that would only use electricity at times of immediate renewable generation being available. Thermal power stations also have demand that peaks during full generation exports but is minimal at other times. Charging such sites for their embedded load would be inequitable and, in some cases, change the economics of their operations. This is consistent with the principles behind the proposed Prudent Discount Regime.
32.	If a gross load approach is used for the residual charge, should injection by both distributed generation and behind-the-meter generation be taken into account, or distributed generation only?	Accessing 'behind-the-meter' generation would require imposing a whole new regime of reporting and controls as it would require collecting data that is currently only of relevance to the party(ies) involved in the behind-the-meter generation and consumption. In situations where there are commercial arrangements set up in relation to the supply of electricity from 'behind the meter' generation, there would potentially have to be a renegotiation of prices and terms in those agreements. That would be highly complex given issues of sunk costs, metering arrangements, on-site utility services, power quality and reliability standards, fuel supplies, complexities of balancing steam requirements and electricity generation, etc. As per Nova's response in Q31 above; if behind-the-meter-generation is taken into account then there should need to be a determination of what the grid demand is expected to be in the absence of the generation running, otherwise the residual charge is not being effected as a charge for electricity transmission, but rather a simple tax on electricity usage.
33.	Is there any other available data that should be used to allocate the residual charge instead of data from the Reconciliation Manager?	
34.	Should the Authority determine the initial allocation of the residual charge in	No. The residual charge needs to be responsive to changes in electricity demand, even if this is limited to substantial changes in demand. By introduction of the AoB

Q No.	Question	Response
	advance as a default or required allocation in the guidelines?	charge, and changing the residual charge to a simple mix of AMD, RCPD and kWh, the drivers for excessive demand response and investment in technologies such as batteries is much reduced. Locking the residual charge to a fixed level over time is likely to be more distortionary on future investment than demand response.
35.	Should a customer's residual charge allocation be adjusted to account for a substantial change to demand due to factors over which it has no control?	Yes. But that should also be intrinsic to the charging methodology rather than specifically requiring an appeal to Transpower to adjust the charge. Albeit it should also be possible to request an immediate change in charges where there is single large change in underlying demand attributable to a particular event e.g. an earthquake.
36.	Should the residual charge apply to both generation and load customers, or only to load customers?	Load customers only. We have discussed this issue in previous submissions. Para B.224 summarises the key issue. Any additional cost on the marginal cost of thermal generation will add to wholesale prices; to the detriment of load and benefit to baseload geothermal generation. Another point not covered here is that much of the grid cost is related to providing security of supply, i.e. n-1 security. Load is the primary beneficiary of that as generators do not require n-1 security as a rule.
	Other	
37.	Are the proposed provisions relating to adjustments appropriate?	There does need to be provision for adjustments.
38.	Should the guidelines specify that a prudent discount applies for the life of the relevant asset unless the parties agree otherwise? Should they specify a different period?	The discount should apply for the expected economic life of the asset.

Q No.	Question	Response
39.	Should the TPM include a price cap? Does a price cap of 3.5% of total electricity bills provide a reasonable balance between the desirability of limiting price shocks and the desirability of transitioning to the new TPM?	
40.	Should the price cap be specified as a percentage of electricity bills or in some other way?	
41.	Should the price cap apply only to load customers, or to generators as well?	
42.	How should the price cap be funded?	The price cap should be funded through the residual charge. The benefit-based charge is a new cost that is being imposed on generators, particularly in the North Island, and it inappropriate to also add an additional charge on generators to subsidise those load customers who are moving from an advantaged situation to a more cost reflective charge.
43.	Are the proposed additional components appropriate? If not, what changes should be made?	
44.	Should the guidelines include a peak charge? If so, should it be a core component of the proposal or an additional component?	The difficulty with retaining the provision for a peak charge is that EDBs will respond by retaining control over load under their contracts with Traders. While the intent is that a peak charge would be short term, EDBs can be expected to cover their options and retain existing load control systems to protect their cost base. Unwinding Use of Systems Agreements (DDA or otherwise) once they are locked in, then becomes a long and protracted exercise. Rather than including provision for a peak charge, Nova suggests making nodal prices more responsive when lines approach 100% of their rated capacity. The case for this is developed under Q55.

Q No.	Question	Response
45.	Should the peak charge be applied only where the grid would otherwise be congested?	If it is to be applied, then yes. However, that may be difficult to determine in many cases, for instance during periods with extremely low South Island hydro storage the capacity to shift energy southwards is constrained between BPE and HAY. Does that mean there should be a peak charge applied on every GXP south of HAY?
46.	Should the peak charge be permanent or should it be phased out? If the latter, should the default phase-out period be over 5 years, 10 years or some other period?	As per nova's comment under Q44. It should be restricted to a fixed period which should be related to the time frame that Transpower may need in order to address the potential congestion in question, e.g. increasing network capacity or until supply conditions change. The networks where it may be introduced should be limited to those areas nominated by Transpower in advance.
47.	Should the guidelines make applying the benefit-based charge to additional and potentially all pre-2019 investments a core component?	A characteristic of the benefit based charges is that they apply an additional cost to generation projects that have been developed in the absence of any previous or anticipated interconnection charges. To the extent that these charges are additional is offset for South Island generators by the removal of HVDC charge. It is already a significant impost on North Island generation without it being extended to further historical assets. This represents a significant loss of value for North Island generation. If the benefit based charge is introduced for all pre-2019 investments, then there should also be provision for reducing the charge in situations where their investment would not have been made if the charge had been known in advance. Take for instance the HLY_SFD line. If Taranaki generators were to pay a substantial proportion of the capital costs for that line, then the decision to locate thermal plant in Taranaki after that line was completed could have been quite different.
48.	In addition to the specific questions above, do you have any further comments on the matters covered in this appendix B?	A reduced Power Factor increases lines losses, which are paid for by all electricity consumers. It therefore seems appropriate for parties contributing to a reduced power factor should cover those costs, either through a charge or for correction equipment.

Q No.	Question	Response
	Appendix C	
49.	Do you have any comments on the matters covered in this appendix C?	
	Appendix D	
50.	Do you agree that the analysis presented in chapter 5 of the second issues paper remains appropriate?	
51.	Do you agree that workably competitive markets provide an appropriate analogy for deriving principles for efficient pricing of the interconnected grid?	
52.	Do you agree with the conclusions of appendix D?	
53.	Do you have any comments on the matters covered in this appendix D?	
	Appendix E	
54.	Do you agree with the conclusions we draw from Transpower's report The role of peak pricing for transmission?	
55.	Do you agree that nodal prices enhanced by RTP, and supplemented if necessary with administrative demand control, are the most efficient means of constraining grid use to capacity?	Yes, however that nodal prices could better reflect the SRMC of demand when circuits are approaching capacity. Currently the non-linear formula for lines losses is simulated by three[1] linear equations in SPD to approximate the losses. This means that approaching the limit of a circuit's capacity, SPD underestimates the losses, and hence the SRMC of any additional units of demand. The result is that even under RTP, nodal prices do not

Q No.	Question	Response
		signal that the grid is approaching capacity as effectively as they should do. This could be corrected by adding a fourth constraint in SPD for each circuit to reflect the higher losses for just the last 1-2% of the circuits rated capacity. Given that lines capacities are not absolute, and are time related, then the slope of that fourth equation could be set at a value where under RTP it acts as dynamic price signal that the circuit utilisation is approaching capacity. In effect it is soft limit on capacity. This early signalling would enhance the ability of consumers to adjust their consumption if they choose to do so. The alternative to this option is a risk that prices may oscillate between having a constraint binding and not, as consumers respond to a large step change between normal prices and a very high constrained price. Adding such an additional losses equation would be economically more efficient than triggering very high prices and would avoid the need for Transpower to apply peak pricing for lines approaching their capacity limits. [1] Other than the HVDC which has six equations simulating lines losses.
56.	Do you agree that the benefit-based charge, in conjunction with the Commerce Commission regulatory regime and nodal prices, is sufficient to ensure efficient investment in the grid and by grid users?	
57.	Do you agree that nodal prices (supplemented if necessary by administrative load control) will be allowed in practice to efficiently restrain grid use to capacity?	Nova's view is that the process would work if supplemented by adding a fourth losses equation as described in Q55 above.
58.	Do you agree that it would not be efficient to provide for a permanent peak	Given the change to SPD proposed above, there should be no need for a strongly signalled Peak Charge.

Q No.	Question	Response
	based charge in addition to nodal prices?	It is necessary however that the Residual Charge include an element of peak charging if it is to be fair and responsive to changing market conditions over time.
59.	Do you agree that the proposed transmission charges are more efficient than the options discussed here? Are there any other options we should consider?	
60.	Do you have any comments on the matters covered in this appendix E?	
	Appendix F	
61.	Should LCE be allocated to the specific investments to which it relates? If not, how should it be allocated?	LCE should be determined for each of specific investments covered by the AoB, but distributed based on the net electricity generated or purchased at each GXP. The complexity and volatility of LCE is such that it is difficult for any distributor to factor it into their pricing. EDB costs and revenues are unrelated to electricity prices, whereas LCE is directly related to electricity prices. As such, distribution of LCE to EDBs does not provide any value or economic benefit. If LCE was distributed to Traders at each relevant GXP in proportion to the energy purchases or sales at the GXP/GIP, then the LCE would provide a small natural hedge to high electricity prices, and the LCE distributed would therefore flow through to consumers in the form of reduced retail electricity prices. For EDBs, the majority of which already pass through the LCE to Traders, this would remove a level of administration that they don't need.
62.	Would the proposed ACOT Code change be desirable to clarify the situation for payment of ACOT under the TPM proposal? Would the resulting code provisions in relation to ACOT be	Nova notes that if the additional peak losses equation is introduced as proposed in Nova's response to Q55 then DG would receive a higher return from generation on those occasions that the DG helped prevent lines from constraining. This should be adequate incentive for efficient investment in DG without requiring specific ACOT payments.

Q No.	Question	Response
	efficient?	
63.	Do you agree that this potential Code amendment to ensure the workability of the TPM will reduce uncertainty? If not, do you think it can be modified so as to ensure uncertainty is reduced? If so, how?	
64.	In addition to the specific questions above, do you have any further comments on the matters covered in this appendix F?	
	Appendix G	
65.	Do you have any comments on the matters covered in this appendix G?]	
	Appendix H	
66.	Over what period should we undertake the vSPD modelling?	Given the volatility in New Zealand's mix of generation from year to year, the vSPD modelling needs to be conducted over a minimum of four years to least smooth some of the more extreme scenarios. However, Nova does not believe the AoB charges should be locked-in based on a single time period. It is inevitable that the market will change over time and the AoB charge must be able to change with it; even if that means it results in a degree of incentive on parties to avoid the charge. Nova believes the AoB charge should be calculated using vSPD on a rolling 4-5 years in arrears, inclusive of any adjustments for major changes in generation or demand.
67.	Should the vSPD modelling adopt a fixed VPO or a variable VPO? In either	Nova favours a variable VPO on the basis that this could be regarded as a counterfactual based on the use of short term energy storage instead of the grid

Q No.	Question	Response
	case, what is the appropriate level of the VPO?	upgrade. The specific assumptions on whether 20% is the right margin could reasonably be determined on the basis potential marginal energy storage costs, i.e. the loss factors involved in storing and releasing energy over time, ignoring capital costs and capacity constraints.
68.	Do you agree with the approach we have taken to net distributed generation? Do you agree with the application of our netting policy for particular generator(s)? If not, please provide details of particular generator(s) so that we can consider whether to amend our netting arrangements.	Yes, as per the points made in Q31 and Q32, it is important that grid-connected co-generation is fully netted off against its non-export load.
69.	Do you consider that the data used in the impacts modelling (in particular, demand and generation volumes) should be adjusted? If so, please provide reasoning/quantitative calculations.	The vSPD modelling places zero value on an increase in security of supply from investments, except to the extent that there may have been an event in 2014 – 18 that was mitigated by the new projects. The NAaN, Otahuhu Substation Diversity and USI Reactive Support will have increased security of supply, and as such there are clearly beneficiaries from these investments. The other issue with the policy of adopting Schedule 1 as the only determinant of the share of benefit from the pre-2019 upgrades is that future growth in the areas benefitting from those investment remain immune from paying for those assets, excepting a small proportion of the residual charge. In these cases, Transpower should be able to allocate charges based on a simpler methodology, and perhaps using the NIGUP project as a comparator in the case of the Auckland focussed projects.
70.	In addition to the specific questions above, do you have any other comments on the matters covered in chapter 5 and this appendix H, including in particular: the indicative year-one transmission charges in chapter 5; and the allocation	

Q No.	Question	Response
	of annual benefit-based charges for the seven major investments included in schedule 1 of the proposed guidelines (appendix A)?	