# Remaining elements of real-time pricing consultation 2019

## Summary of submissions

28 June 2019

# Summary of submissions on our March 2019 real-time pricing consultation

1.1 We published a consultation paper, *Remaining elements of real-time pricing*, on 19 March 2019 seeking views on three remaining design elements of our proposed design for real-time pricing in the wholesale spot market (RTP).

1.2 Submissions closed on 30 April 2019. We received eleven submissions from the following parties. The consultation paper and all submissions are published on the Authority's website at https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/consultations/#c17972.

**Table 1: List of submitters on our March 2019 consultation**

| Submitter | Role |
|---|---|
| Contact Energy Limited<br>Genesis Energy Limited<br>Mercury Energy Limited<br>Meridian Energy Limited<br>Trustpower Limited | Large gentailer |
| Independent Electricity Generators Association (IEGA) Incorporated<br>New Zealand Wind Energy Association (NZWEA) | Industry association |
| Major Electricity Users' Group (MEUG) | Major consumers |
| Transpower NZ Limited | Grid owner and system operator |
| Orion NZ Limited | Electricity distributor |
| Enel X | Load aggregator |

1.3 Responses by individual submitter are presented in alphabetical order in section 1 from page 3, grouped by consultation question. Additional comments are grouped by theme in section 2 from page 38.

## Section 1 Direct responses to consultation questions

**Direct responses** to questions asked in the consultation paper are presented in normal text.

Responses in *italics* are **not direct responses** to the question, but were extracted from other parts of the submission.

Text in square brackets [] has been added by the Authority to improve clarity.

| Q1. Do you agree with our proposed criteria for distributed generation to be eligible for dispatch-lite? If not, please explain your reasoning. | |
|---|---|
| Contact Energy | Agree |
| Enel X | Yes. However, further clarity on the following issues would be beneficial:<br>- When SCADA would/would not be required. The current wording affords the system operator discretion on when SCADA may or may not be required. Greater guidance on this in the final design would be valuable so that potential participants can weigh up the costs and benefits of participation upfront.<br>- What compliance looks like, e.g. what is "too often" when it comes to the ability of a dispatch-lite generator to say no to a dispatch notification?<br>- Other technical obligations that would apply, e.g. ramp rates.<br>These comments apply equally to the dispatch-lite demand framework. |
| Genesis Energy | We consider the dispatch-lite provisions in the consultation paper are improved compared with the earlier draft RTP proposal, particularly noting the inclusion of distributed generation (**DG**). This will promote innovation by enabling emerging technologies (i.e. some DG) to participate.<br>In our view, the System Operator (**SO**) should ultimately determine eligibility for any DG. We believe costs of assessing eligibility should be borne by the dispatch-lite participants. |
| *IEGA* | *In addition, the IEGA requests the Authority consider the option of block-dispatch for generation sites connected to different GXPs as a component of distributed generation-lite. Block dispatch will bring the benefits of distributed generation participation in the wholesale market at a lower cost to individual generation plant owners as an aggregator or contracted third party could manage the Code obligations.* |

| Q1. Do you agree with our proposed criteria for distributed generation to be eligible for dispatch-lite? If not, please explain your reasoning. | |
|---|---|
| | *The IEGA agrees with the Authority's proposed criteria for distributed generation to be eligible to opt-in to the dispatch-lite process. We agree that the current thresholds in the Code, that have existed and operated successfully since the wholesale market was established, should form the basis of the criteria for distributed generation-lite.* |
| Mercury Energy | We agree in principle with the eligibility criteria for distributed generation. However, we would like more refinement of the criteria to make them clearer and we'd like to see further analysis of the implications of the potential impacts of those aspects that are clear. In particular, the 30MW threshold seems high and may have a cumulative unintended impact on the market, in the unlikely event that many (~30MW capacity) distributed generators opt in and are active in the market. |
| Meridian Energy | Yes. |
| MEUG | Agree. |
| NZWEA | The Association agrees it is practicable to use the current thresholds contained in the Code as these have proven over time to operate successfully. |
| *Orion* | *19. Of the various features set out in Table 1, we consider that compliance is problematic and needs further specification. Unless the dispatch-lite load or generation is separately metered, it will be very difficult to determine with any precision whether it responded as expected. On the other hand, if it is separately metered, it may be difficult to determine whether it was simply reconnected to another non-dispatchable demand / generation metering point at the same location at the same time (an EV is the obvious example).*<br>*20. We doubt that the contemplated monthly assessment is scalable if there are many thousands of participants.* |
| Transpower | We defer to industry participant response. |
| *Trustpower* | *1.1.4 Trustpower's response to the particular questions (1-21) in the Paper is in the affirmative.* |

| Q2. Do you agree with our proposed criteria for purchasers to be eligible for dispatch-lite? If not, please explain your reasoning. | |
|---|---|
| Contact Energy | Agree |
| Enel X | The dispatch-lite demand framework currently proposes to allow participation by retailers and direct purchasers only. However there are already opportunities for, and benefits in, these parties undertaking the price/demand-responsiveness envisaged by the dispatch-lite framework. Given this, it is not immediately clear that there will be any significant participation in the dispatch-lite demand framework.<br>In Enel X's view, there will not be a meaningful level of wholesale demand response in NZ's energy market until:<br>• load flexibility is separated from retail, and<br>• third parties are able to access the energy market directly using the aggregated flexibility of its customers.<br>While theoretically efficient to have all energy users responding to spot prices, most cannot and do not want to manage the risks of spot price exposure. Separating load flexibility from retail means consumers can remain on the fixed price variable volume contracts that they prefer, but also access the value associated with the portion of their load that is flexible. However, retailers do not have a natural incentive to encourage demand reductions by their customers. Allowing third parties (whose incentives are aligned with the customers') to access and aggregate this combined capability can deliver benefits for participating consumers and the energy market more broadly.<br>Opening up the dispatch-lite frameworks to independent parties (or enabling their participation through other means) would see greater participation by the demand side – bringing about greater market efficiencies and more competition and choice for consumers. We propose that third party access to the dispatch-lite framework be explored further, and perhaps in conjunction with the EA's project on multiple trading relationships. |
| Genesis Energy | Yes. |
| Mercury Energy | Yes. |
| Meridian Energy | Yes. |
| MEUG | Agree. |

| Q2. Do you agree with our proposed criteria for purchasers to be eligible for dispatch-lite? If not, please explain your reasoning. | |
|---|---|
| NZWEA | The Association supports the proposal but notes, in the Association's view, the aggregation of controllable load sources will become a core market activity as the investment in behind the meter capability and intermittent generation increases. |
| *NZWEA* | *11. The Association further notes the importance of dispatch-lite in its original form to support dispatchable demand as this better enables the benefits of behind the meter technologies to be realised to optimise electricity sector efficiency and avoid unnecessary investment.* |
| *Orion* | *21. We note in passing in relation to para 3.24(a) of the paper that there are some parts of the grid where neither the purchaser nor the system operator will be able to tell in real time what GXP an ICP is connected to (for example Orion regularly[1] switches load between Islington and Bromley). If there is material - bid or unbid - demand response available, it might not be occurring at the GXP the SO / consumer / participant thinks it is.* |
| Transpower | We defer to industry participant response. |
| *Trustpower* | *1.1.4 Trustpower's response to the particular questions (1-21) in the Paper is in the affirmative.* |
| IEGA | [No response to this question] |

[1] Roughly once a month on average and for several days at a time

| Q3. Do you agree participants providing SCADA telemetry should be eligible for dispatch-lite? If not, please explain your reasoning. | |
|---|---|
| Contact Energy | Agree. SCADA should not be a requirement for dispatch-lite |
| Enel X | Yes. Enel X agrees that SCADA should not be a required condition of participating in the dispatch-lite framework. A requirement to have SCADA capability would be a significant barrier to participation. While a lack of SCADA could compromise the accuracy of load forecasts, there are other telemetry arrangements that can be utilised to give the system operator a better picture of the status of loads behind a GXP. As above, the more clarity the EA can provide on when SCADA (or other telemetry arrangements) would or would not be required, the better. |
| Genesis Energy | Yes. Additionally, in our view, the SO should have the best information available to ensure accuracy. The transition to RTP provides an opportunity to accommodate a 'SCADA-lite' solution with lower refresh and reliability requirements, which should be feasible and relatively inexpensive (at a threshold of e.g. greater than one megawatt). We believe the SO should consider whether SCADA-lite would be useful. |
| *IEGA* | *The IEGA also supports the Authority's proposed approach to the requirement for SCADA telemetry for distributed generation. Our understanding is that the discretion currently held by the System Operator would continue to apply and other distributed generation will not be required to install SCADA telemetry.* |
| Mercury Energy | While we appreciate that SCADA telemetry has been selected for pragmatic reasons we would prefer more relevant and precise eligibility criteria over using SCADA telemetry as the bright line for who is eligible if this can be achieved. |
| Meridian Energy | Yes. |
| MEUG | Agree. To be clear the proposal is that SCADA is not needed for dispatch-lite unless required by the System Operator. |
| NZWEA | The Association supports the EA's proposed approach that participants who wish to use SCADA telemetry should be eligible for dispatch-lite. |
| Transpower | We defer to industry participant response. |

| Q3. Do you agree participants providing SCADA telemetry should be eligible for dispatch-lite? If not, please explain your reasoning. | |
|---|---|
| *Trustpower* | *1.1.4 Trustpower's response to the particular questions (1-21) in the Paper is in the affirmative.* |
| Orion | [No response to this question] |

| Q4. Do you agree combining an acknowledgement response via the dispatch system with an obligation to immediately rebid or reoffer is the best design option? If not, please explain your reasoning. | |
|---|---|
| Contact Energy | Agree, although even for automated systems several minutes must be allowed to respond to dispatch notifications and rebid/reoffer. This is because systems may generate rebid/reoffers on an interval basis, rather than "on demand" when a dispatch notification is received. |
| Enel X | Yes. |
| Genesis Energy | We are concerned this is twice as complicated as is required and wonder if it would be simpler to just rebid or reoffer, and still provide the SO and market with enough information. The two-step process could be perceived to be a participation barrier, although this is likely to be mitigated if the process is automated. |
| *IEGA* | ***Saying no to a dispatch notification***<br>*The proposal has two steps using two different forms or processes:*<br>• *Send a specific type of acknowledgment to the dispatch notification through the dispatch system; and then*<br>• *Immediately rebid or reoffer as non-dispatchable using another method for the remainder of that trading period and until the end of the next gate closure period.*<br>*We support this two-step process if the two distinct steps cannot be avoided. Our motivation is to make this dispatch-lite process easy to encourage participation.* |
| Mercury Energy | In principle, yes, although as with our previous responses, we would like to see clearer eligibility criteria established. |
| Meridian Energy | Yes. |
| MEUG | Having clarity of a dispatch-lite participant's intentions is reasonable with the additional compliance responsibility falling on the participant. As the paper notes those participants have an incentive to automate such functionality in required changes for the DSE project. |
| NZWEA | The Association supports the two-step process proposed. While the objective of dispatch-lite is for a simplified process that recognises the scale of the volume being traded not being able to respond to a dispatch notification should have requirements to |

| Q4. Do you agree combining an acknowledgement response via the dispatch system with an obligation to immediately rebid or reoffer is the best design option? If not, please explain your reasoning. | |
|---|---|
| | confirm position. |
| Transpower | We defer to industry participant response. |
| *Trustpower* | *1.1.4 Trustpower's response to the particular questions (1-21) in the Paper is in the affirmative.* |
| Orion | [No response to this question] |

| Q5. Do you agree gate closure for all disptach-lite participants should be set at 30 minutes (one trading period), the same as for current embedded generators? | |
|---|---|
| Contact Energy | Agree |
| *Contact Energy* | ***4. Reduction in gate closure to 1 Trading Period***<br>*Contact's view is that the gate closure period for all market participants should be 1 trading period to realise the full potential RTP due to the increased accuracy of offers or bids. The forecasted price within 1 trading period will be different to those outside that timeframe if there is an increased number of demand participants in the bidding process. Without a reduced gate closure period there is potential for a mismatch, participants will take action based on different price forecasts resulting in an inefficient market outcome.* |
| Enel X | Yes. |
| Genesis Energy | Yes. We consider the same rules should apply to all market participants, not just dispatch-lite participants, unless there is clear justification for differential treatment. |
| *IEGA* | ***Gate closure would be 30 minutes***<br>*The IEGA supports gate closure of 30 minutes for dispatch-lite participants.* |
| Mercury Energy | Yes. |
| Meridian Energy | Yes. |
| MEUG | Agree.<br>MEUG notes the EA should consider in a review of the gate closure regime (separate from the RTP project) if the current 1-hour for full dispatchable demand and full offered generation should change to 30 minutes. |
| NZWEA | The Association supports a gate closure of 30 minutes for dispatch-lite participants. |

| Q5. Do you agree gate closure for all disptach-lite participants should be set at 30 minutes (one trading period), the same as for current embedded generators? | |
|---|---|
| Transpower | We defer to industry participant response. |
| *Trustpower* | *1.1.4 Trustpower's response to the particular questions (1-21) in the Paper is in the affirmative.* |
| Orion | [No response to this question] |

| Q6. Do you agree with the proposed compliance arrangements for dispatch-lite? If not, please explain your reasoning. | |
|---|---|
| Contact Energy | Agree |
| Enel X | Yes. However, the more guidance the EA can put in its final design on what constitutes compliance, the better. Upfront guidance, for example on what constitutes "repeatedly saying no to dispatch instructions" will give a better indication of expected participation in the framework. Strict compliance obligations that mirror those imposed on full offered generation and dispatchable demand participants will not result in any significant participation. |
| Genesis Energy | We note that the reduced compliance burden for dispatch-lite participants will require the SO to administer different rules for different participants, which adds complexity. The SO should consider whether it has the appropriate resources and capability to account for this. |
| *IEGA* | ***Saying no to dispatch notifications rarely***<br>*There are two points in this section:*<br>• *Dispatch-lite participants must notify the System Operator if they are not going to comply with a dispatch instruction (or breach the Code)*<br>• *Dispatch-lite participants can say no to a System Operator dispatch instruction on rare occasions*<br>*The IEGA has limited knowledge of, and has not reviewed, the Code as it applies to participants that are currently dispatched in this regard. The IEGA supports these proposals if they are no more onerous than the requirements for participants that are currently dispatched, on the basis that dispatch-lite participation will not increase the potential for unexpected changes in net load.*<br>*We assume the same bone fide circumstances for dispatched generation will apply to dispatch-lite participants and can be part of the 'rare' occasions when a dispatch-lite participant decides not to comply with a dispatch instruction.* |
| Mercury Energy | We would prefer greater clarity around the obligations for dispatch-lite participants rather than relying on SO discretion. The proposed guidelines and policy statement should be circulated for feedback ahead of being adopted. It is important that all market participants understand the basis and scope of dispatch-lite participation in RTP to ensure its effectiveness. |
| Meridian Energy | Yes. However, as discussed in the cover letter of this submission Meridian would also appreciate the Authority or system operator regularly reporting on the instances in which participants have not followed dispatch notifications. |

| Q6. Do you agree with the proposed compliance arrangements for dispatch-lite? If not, please explain your reasoning. | |
|---|---|
| *Meridian Energy* | *If and when dispatch-lite is implemented Meridian would like the Authority to consider regular reporting on the instances when participants have not followed dispatch notifications. Such transparency will help other participants to understand the extent to which dispatch-lite participants can be relied upon and the potential impact on prices as a result of their ability to say no to dispatch instructions. Transparency would also be a strong deterrent to gaming behaviour and give all participants some insight into how the system operator will exercise its discretion to suspend or revoke a dispatch-lite participant's approval if they repeatedly said no to dispatch notifications. This reporting would be in addition to the system operator's publication of suspension and revocation criteria in their policy statement and also in addition to the dispatch-lite participant's obligation to signal non-compliance and rebid or reoffer as non-dispatchable for the current and subsequent trading periods.* |
| MEUG | Agree. |
| NZWEA | The Association has a limited knowledge of the Code but supports the proposed compliance requirements so long as they are no more onerous than the requirements for participants that are currently dispatched. |
| Transpower | We defer to industry participant response. |
| *Trustpower* | *1.1.4 Trustpower's response to the particular questions (1-21) in the Paper is in the affirmative.* |
| Orion | [No response to this question] |

| Q7. Do you agree with the proposed method to allow dispatch-lite participants to withdraw from dispatch? If not, please explain your reasoning. | |
|---|---|
| Contact Energy | Agree |
| Enel X | Yes. As noted by the EA, allowing participants to withdraw from dispatch means they do not need to operate a 24/7 trading desk. In Enel X's view, allowing this will also see greater interest in the dispatch-lite framework by enabling those loads or generators that are not available for dispatch 24/7 to participate. |
| Genesis Energy | No comment. |
| *IEGA* | ***Electing to be non-dispatchable*** <br> *As above, electing to be non-dispatchable must be a component of the current wholesale market dispatch process. The IEGA supports these proposals if they are no more onerous than the requirements for participants that are currently dispatched, on the basis that dispatch-lite participation will not increase the potential for unexpected changes in net load.* |
| Mercury Energy | While we appreciate that dispatch-lite market participants may not be able to dispatch 24/7 as bigger players do (for example because they do not operate outside normal business hours), we would like more analysis around the implications of many participants being able to withdraw dispatch simultaneously. This would be the case particularly if those participants were dispatching 30MW each. |
| Meridian Energy | Yes. |
| MEUG | Agree. |
| NZWEA | Response as for question [6]. |
| Transpower | We defer to industry participant response. |
| *Trustpower* | *1.1.4 Trustpower's response to the particular questions (1-21) in the Paper is in the affirmative.* |

| Q7. Do you agree with the proposed method to allow dispatch-lite participants to withdraw from dispatch? If not, please explain your reasoning. | |
|---|---|
| Orion | [No response to this question] |

| Q8. Do you agree we should implement dispatch-lite as part of RTP, should we decide to proceed? If not, please explain your reasoning. | |
|---|---|
| Contact Energy | Agree. We're not sure the Authority's worked examples in Appendix D are applicable to all loads. The examples assume a load could switch off / ramp down for a 5 minute period, then switch back on for the next 5 minutes, and continuing switching off / on in 5 minute intervals. Many electrical loads/equipment, and the control systems controlling those loads will not allow/enable this. For example, after a load shutdown process, the load may need several hours to restart and be in a position for another event to occur. For example in Figure 13, when the load receives a dispatch notification at the 10 minute mark to switch back on, it would need to bona fide / rebid / reoffer as non-dispatchable for the remainder of the trading period (and the following gate closure period) to ensure it was not dispatched again. (In Figure 13 it would not reduce load at the 15 minute mark and the 25 minute mark). The Authority may want to consider the implications of loads responding like this in the final design. Many loads are far more suited to, for example, responding to a Transpower demand response program event notification which dispatches the load for a fixed period, for example from 5.30-7.30pm. |
| Enel X | Yes. Enel X agrees with the EA's assessment of the benefits of the dispatch-lite framework. |
| Genesis Energy | Yes, the proposal outlined in the consultation paper is much improved compared with the initial proposal. Ultimately though, we believe the SO should determine whether to implement it subject to the availability of resources and internal capability. |
| Mercury Energy | We strongly support implementation of RTP. We believe the initiative stands on its own merits regardless of whether dispatch-lite is also implemented. We see dispatch-lite as 'nice to have' as it will, if used by market participants, add a depth to the market but it is not a prerequisite for introducing RTP. |
| Meridian Energy | No, we consider it a distinct proposal and that it should be progressed following a 'bedding in' period for real-time pricing. Further discussion on this point is in the cover letter for this submission. |
| *Meridian Energy* | *Meridian supports the expansion of the dispatch-lite proposal to also include smaller-scale generation. In theory, opening dispatch-lite to a broader group of potential participants would enable greater benefits should smaller scale generators choose to engage. However, we continue to question whether dispatch-lite needs to be progressed as part of real-time pricing.*<br><br>*We doubt the extent to which dispatch-lite will be used initially but acknowledge that the Authority will be best placed to assess participant interest in using dispatch-lite now or in the immediate future. In the absence of proven demand for dispatch-lite we consider it best to progress it later. The move to real-time pricing will be a complex transition for the industry and one that will only be further complicated by the simultaneous addition of dispatch-lite. There is absolutely no reason why the two changes need to be tackled together as part of the same project. Once real-time pricing is well established the introduction of dispatch-lite should be reconsidered. We expect that the Authority will be resistant to delays and will want to provide an enabling environment for* |

| Q8. Do you agree we should implement dispatch-lite as part of RTP, should we decide to proceed? If not, please explain your reasoning. | |
|---|---|
| | *dispatchable demand and small-scale generation sooner rather than later.  This is understandable.  However, we consider the risk of a more complex transition to real-time pricing outweighs any benefits that might accrue from implementing dispatch-lite at the same time.* |
| MEUG | Agree there is likely to be a net benefit implementing dispatch-lite at the same time as the rest of RTP rather than delaying. |
| *MEUG* | *2. MEUG supports dispatch-lite being implemented at the same time as the rest of RTP.* |
| NZWEA | The Association supports the implementation of dispatch-lite. |
| *NZWEA* | *13. The Association notes paragraphs 3.56 and 3.57 and 3.58 of the Consultation Paper and agrees that the RPT Project, with dispatch-lite for both distributed generation and dispatchable demand, is an important development to future proof the wholesale market and support the development of renewable electricity generation.* |
| Transpower | We defer to industry participant response. |
| *Trustpower* | *1.1.4 Trustpower's response to the particular questions (1-21) in the Paper is in the affirmative.* |
| IEGA, Orion | [No response to this question] |

| Q9. Do you agree reserve pricing under RTP should place a higher cost on scarcity of FIR than scarcity of SIR? If not, please explain your reasoning. | |
|---|---|
| Contact Energy | Agree |
| Enel X | Yes. |
| Genesis Energy | Yes. |
| Mercury Energy | Yes, but we believe FIR and SIR prices should be reviewed regularly as market conditions are likely to change over time and in the future the relative value of FIR and SIR may change. |
| *Mercury Energy* | *While Mercury agrees that for now reserve pricing under real-time pricing should place a higher cost on scarcity of FIR than scarcity of SIR we believe this relativity should be reviewed regularly as market conditions are likely to change over time and in the future the relative value of FIR and SIR may change.* |
| Meridian Energy | Yes. |
| Transpower | Yes. We consider FIR has greater value in arresting frequency collapse so the higher cost on scarcity of FIR should incentivise FIR provision. |
| *Trustpower* | *1.1.4 Trustpower's response to the particular questions (1-21) in the Paper is in the affirmative.* |
| IEGA, MEUG, NZWEA, Orion | [No response to this question] |

| Q10. Do you consider the risk-violation curve approach would increase incentives or opportunities for gaming? Please explain your reasoning. | |
|---|---|
| Contact Energy | No. The Code of Conduct sets sufficient boundaries for participant behaviour. |
| Enel X | No. Enel X agrees with the Authority's assessment that times of scarcity warrant greater scrutiny, and thus it should be reasonably easy to identify instances of gaming. |
| Genesis Energy | We expect that trader conduct standards should be enforced regardless of participant type or status. This should reduce any incentive or opportunity for gaming. |
| Mercury Energy | Not unless the ongoing monitoring by the Electricity Authority (which acts as an effective deterrent and ensures any questionable behaviour is addressed when it arises) becomes ineffective. |
| *Mercury Energy* | *We support the risk violation curve approach for determining prices for reserves under real-time pricing and do not believe this increases incentives or opportunities for gaming. Ongoing monitoring by the Authority is an effective safeguard against gaming by market participants.* |
| Meridian Energy | No. |
| Transpower | We defer to industry participant response. |
| *Trustpower* | *1.1.4 Trustpower's response to the particular questions (1-21) in the Paper is in the affirmative.* |
| IEGA, MEUG, NZWEA, Orion | [No response to this question] |

| Q11. Do you agree we should implement the risk-violation curve we have described to handle reserve shortfalls under RTP? If not, please explain your reasoning. | |
|---|---|
| Contact Energy | Agree in principle but the prices cannot be finalised until a review of the scarcity pricing values as mentioned in Q15. |
| Enel X | Yes. The risk-violation curve approach seems sensible. However, in Enel X's view, the curve should be designed so that:<br>• instantaneous reserve deficits occur before load shedding<br>• instantaneous reserve deficits do not occur if there is offered generation available, even if this generation is offered above energy scarcity values. |
| Genesis Energy | Yes, as compared with the alternative option tested. |
| Mercury Energy | Yes. We believe a risk violation curve is the appropriate methodology to handle reserve shortfalls in RTP. |
| Meridian Energy | Yes. |
| *Meridian Energy* | *Meridian agrees with the proposed 'risk-violation curve' model for determining reserve shortfall prices under real-time pricing. We understand at a high level the need for such an approach under real-time pricing given:*<br>• *the inability to manually process reserve shortfalls using the current virtual reserve provider; and*<br>• *the difficulties of managing multiple risk setters.* |
| *Orion* | ***Reserve shortfalls***<br>*22. The proposed approach to handling reserve shortfalls seems reasonable. We believe it is likely to result in higher prices overall – other things equal - but not inappropriately higher. At the workshop on 29 March it was helpfully explained that the New Zealand market's approach of co-optimisation, which we understand is unusual internationally, requires a solution like that proposed. It would be helpful at some stage if the Authority explained why a different approach – not co-optimising – would not be a superior overall approach given its significant influence on RTP design.*<br>*23. As we noted at the workshop, the interaction between scarcity energy 'offer' prices and shortfall reserved prices needs to be considered in the final design. This is because the two prices can, in normal (non scarcity) circumstances, interact in ways that make the energy price materially higher than the highest dispatched energy offer. Given the rationale for scarcity prices – effectively a cost of non-supply – we are not sure the normal logic applies in scarcity situations; the cost of non-supply of energy* |

| Q11. Do you agree we should implement the risk-violation curve we have described to handle reserve shortfalls under RTP? If not, please explain your reasoning. | |
|---|---|
| | *cannot be, or should not be able to be, more than the value of the energy not supplied. Put another way, customers not having reserve when they don't have energy does not make them worse off.* |
| Transpower | We support a configuration that reduces the risk of demand management measures. |
| *Trustpower* | *1.1.4 Trustpower's response to the particular questions (1-21) in the Paper is in the affirmative.* |
| IEGA, MEUG, NZWEA | [No response to this question] |

| Q12. Which configuration of the risk-violation curve do you consider we should adopt? Please explain your reasoning. | |
|---|---|
| Contact Energy | As per our Q11 response we cannot fully comment on these specific curves until scarcity values have been reviewed.<br>We do note that the lower price risk-violation curve has pricing below historic generation of last resort offers from plant such as Whirinaki. This has the potential for emergency generation not being dispatched in favour of running the grid in a less secure state. This suggests these reserve values are too low. |
| Enel X | No comment. |
| Genesis Energy | We support the configuration proposed in Table 7. The Authority's related analysis and conclusions appear sound. |
| Mercury Energy | We prefer a risk violation curve that incentivises all energy and reserve offers to clear ahead of any trigger for shortfall pricing. We understand this is difficult to ascertain given the variable nature of historical offers and the uncertain nature of the future. As such we recommend a hybrid curve with higher price and lower volumes (more tranches) which would better suit the uncertainty while still maintaining a graduated response. |
| Meridian Energy | Meridian prefers the lower priced 'risk-violation curve' with three tranches priced below the first default energy scarcity pricing block at $10,000/MWh. We consider it sensible to increase the chance of reserve shortfall before energy deficit and thereby constrain prices. The lower priced 'risk-violation curve' prices will still be sufficient to signal scarcity. |
| *Meridian Energy* | *The proposed 'risk-violation curve' approach would set a rising price for reserve as the quantity of reserve shortfall grows, this appears to more accurately reflect the economic cost of leaving risk sources uncovered. Meridian supports the use of a lower priced 'risk-violation curve' to increase the likelihood of reserve shortfall before energy deficit.* |
| *MEUG* | *The design philosophy of using a risk-violation curve rather than static steps is an improvement to estimate boundary costs for reserve shortfalls. However, we do not have a view on the technical details of how those curves should be estimated.* |
| Transpower | We support a configuration that reduces the risk of demand management measures. |
| *Trustpower* | *1.1.4 Trustpower's response to the particular questions (1-21) in the Paper is in the affirmative.*<br>[Trustpower has confirmed that they agree with the proposed lower price version of the risk-violation curve.] |

| Q12. Which configuration of the risk-violation curve do you consider we should adopt? Please explain your reasoning. | |
|---|---|
| IEGA, NZWEA, Orion | [No response to this question] |

| Q13. Should we set a total reserve shortfall quantity limit if we implement the risk-violation curve under RTP? Please explain your reasoning. | |
|---|---|
| Contact Energy | More work is needed on this from an engineering perspective regarding what the minimum quantity is to avoid cascade failure of the grid. We do expect a limit is required. |
| Enel X | No comment. |
| Genesis Energy | Yes, as a quantity limit draws an arbitrary line to signal that there is a point where load shedding ought to occur. That said, we believe the SO should ultimately determine whether this is appropriate having regard for Principal Performance Obligations (**PPOs**).<br>[Genesis has confirmed they supported using a set limit] |
| Mercury Energy | No. There is no limit to reserve shortfall. If a limit is required for model purposes, then it should be set larger than what js technically feasible under current plant/transmission settings. |
| Meridian Energy | We understand the rationale for specifying a limit on the quantity of reserve shortfall for the first four tranches (50MW) of the 'risk-violation curve'. For the final tranche, the 100MW limit seems less well justified. It is highly likely that following the last tranche of the 'risk-violation curve' load shedding will occur on the remaining 80 percent of load priced in as the $20,000/MWh scarcity block. At that point, load shedding will be beyond the approximate 'comfortable' level of load management within distribution networks – meaning it would be less reliable and more difficult to target, driving up costs. Allowing a larger or unlimited top tranche of the 'risk-violation curve' should be considered in order to avoid those circumstances. |
| Transpower | No. We consider the current industry-preferred practice should continue i.e. to redispatch all spinning reserve as energy and rely on interruptible load and AUFLS to manage a contingent event during a shortfall. |
| *Trustpower* | *1.1.4 Trustpower's response to the particular questions (1-21) in the Paper is in the affirmative.*<br>[Trustpower has confirmed that they have no position on a total shortfall limit.] |
| IEGA, MEUG, NZWEA, Orion | [No response to this question] |

| Q14. Do you agree a new type of formal notice to cover periods of reserve shortfall under RTP is not warranted? If not, please explain your reasoning. | |
|---|---|
| Contact Energy | Agree, the price signal is sufficient enough notice. |
| Enel X | No comment. |
| Genesis Energy | Yes. We consider that Grid Emergency Notices (**GENs**) are generally appropriate to cover periods of reserve shortfall. We note however that the SO at times only communicates GENs to participants it sees are relevant, which excludes other participants being able to manage risk. However, we also acknowledge that some GEN situations are necessarily managed verbally based on an assessment of information available at the time. |
| Mercury Energy | No. Given the objective is to facilitate greater participation in RTP it is important that small players potentially unfamiliar with the market and lacking large scale resources get access to information instantly. There are low cost technological solutions that can be deployed to ensure information is transmitted, such as text alerts for example. |
| *Mercury Energy* | *Mercury believes a new type of formal notice to cover periods of reserve shortfall under real-time pricing is warranted given a) with the inclusion of 'dispatch lite' we can expect more smaller players with less market experience and less resource to potentially participate in the real-time market and b) there are low cost technological solutions that could be deployed to ensure information is accurately and efficiently transmitted, such as text alerts for example.* |
| Meridian Energy | Yes. |
| Transpower | We defer to industry participant response. |
| *Trustpower* | *1.1.4 Trustpower's response to the particular questions (1-21) in the Paper is in the affirmative.* |
| IEGA, MEUG, NZWEA, Orion | [No response to this question] |

| Q15. Do you agree with the proposed methodology to calculate the scarcity pricing values? If not, please explain your reasoning. | |
|---|---|
| Contact Energy | Agree subject that all new technologies and that true VOLL costs are accounted for. |
| *Contact Energy* | ***2. Scarcity and Reserve Price Curve Values***<br>*Contact also has concerns regarding scarcity pricing values proposed for RTP (as per October 2017 submission). Contact supports the review of these prices (reliability parameters) to ensure that there are sufficient signals for investment and that all reasonable offers are cleared.*<br>*Setting these scarcity values too low effectively means signalling demand shedding (pre-contingent action) before signalling for increased reserve offers to manage the risk of post-contingent demand shedding using automatic under-frequency load shedding (AUFLS). Our view is that whatever price values are finalised for scarcity and reserves there needs to be a buffer maintained between the two, this will ensure that reserves shortfalls are signalled prior to demand shedding signalling even under a multiple binding risk scenario (price multipliers).* |
| Enel X | No comment. |
| Genesis Energy | Yes, the proposed process appears reasonable. We accept that the proposed methodology only informs the reliability parameters and that an element of judgement will be employed. |
| Mercury Energy | Broadly yes. Relativity must be maintained to other shortfall related price settings. |
| Meridian Energy | Yes. |
| MEUG | Agree. |
| *Orion* | ***Scarcity pricing values***<br>*24. As we noted in our October 2017 submission, there is often considerable resource available at a lower cost than the lowest priced tranche of existing scarcity prices. We do not believe it is reasonable to argue that prices that are higher than they need to be can be efficient.* |

| Q15. Do you agree with the proposed methodology to calculate the scarcity pricing values? If not, please explain your reasoning. | |
|---|---|
| Transpower | Yes. |
| *Trustpower* | *1.1.4 Trustpower’s response to the particular questions (1-21) in the Paper is in the affirmative.* |
| IEGA, NZWEA | [No response to this question] |

| Q16. Do you agree the Authority should have an obligation to review the scarcity pricing values at least once every five years? If not, please explain your reasoning. | |
|---|---|
| Contact Energy | Agree, but would prefer 1-2 years initially for the review period to address any issues post RTP implementation. |
| Enel X | Yes. However, given this is a reasonably significant change to the current arrangements, it may be prudent to review the framework one year after implementation to assess its effectiveness and identify any issues, and then conduct five-yearly reviews after that. |
| Genesis Energy | Yes. |
| Mercury Energy | Yes, although we would recommend a more frequent review period, for example biannually given market conditions can change rapidly and may do so in the future as emerging technologies are adopted and NZ moves to produce more renewable energy. |
| *Mercury Energy* | *We support the scarcity pricing proposals although a more frequent review period is preferable to ensure changes in market conditions and technology are accounted for. A biennial review would be better than every five years.* |
| Meridian Energy | Yes. |
| *Meridian Energy* | *Meridian supports the Authority's intention to review the dollar amounts assigned to the scarcity pricing values before real-time pricing goes live and every five years by requirement of the Code.* |
| MEUG | Agree. This periodic review requirement is consistent with our submissions in 2017 to include such.[2] |
| Transpower | We agree with an obligation to review but consider any changes arising (with changed values) should not be so frequent that the market loses an ability to forecast. We note the figures being used are already based on information from 2011 so future changes to scarcity values may also endure longer than the review cycle. |
| *Trustpower* | *1.1.4 Trustpower's response to the particular questions (1-21) in the Paper is in the affirmative.* |

[2] Refer MEUG submission, response to question 4, 10th October 2017, https://www.ea.govt.nz/dmsdocument/22717-major-electricity-users-group

| Q16. Do you agree the Authority should have an obligation to review the scarcity pricing values at least once every five years? If not, please explain your reasoning. | |
|---|---|
| IEGA, NZWEA, Orion | [No response to this question] |

| Q17. Do you agree with the objectives of the proposed amendment? If not, why not? | |
|---|---|
| Contact Energy | Agree, this amendment would result in a more efficient market outcome as both demand and generation participants will have a better indicator of actual real time price. This is subject to scarcity and reserve risk violation prices and quantities being set at appropriate levels to signal the appropriate actions in real time (see our general response, note 2 'Scarcity and Reserve Price Curve Values') and appropriate investment in energy and/or reserve products. |
| Enel X | Yes. |
| Genesis Energy | Yes. |
| Mercury Energy | Yes. |
| Meridian Energy | Yes. |
| MEUG | Agree. |
| Transpower | Yes. |
| *Trustpower* | *1.1.4 Trustpower's response to the particular questions (1-21) in the Paper is in the affirmative.* |
| IEGA, NZWEA, Orion | [No response to this question] |

| Q18. Do you agree with the objective of the proposed Code amendment? If not, please explain your reasoning. | |
|---|---|
| Contact Energy | Agree subject to our response in Q17. |
| Enel X | Yes. |
| Genesis Energy | Yes. |
| Mercury Energy | Yes. |
| Meridian Energy | Yes. |
| MEUG | Agree. |
| Transpower | Yes, but we consider clause 13.69AAA should be more specific about the provision of demand values from the grid owner's meters.<br>We have proposed re-drafting in the main body of this submission. |
| *Trustpower* | *1.1.4 Trustpower's response to the particular questions (1-21) in the Paper is in the affirmative.* |
| IEGA, NZWEA, Orion | [No response to this question] |

| Q19. Do you agree with the cost-benefit assessment? In particular: – what (if any) other sources of benefit should be included in the assessment? – what is your view on key assumptions, such as the level of improved demand response enabled by RTP? – what (if any) other sources of costs should be included in the assessment? Please explain your reasoning. | |
|---|---|
| Contact Energy | Somewhat agree. The Authority states that most of the quantifiable benefits come from more efficient demand response. Most unscheduled demand shedding at present is by EDBs. Without EDB's providing more information to improve load forecasts, we believe a number of the benefits of RTP may not be fully recognised. |
| Enel X | Some of the benefits of the real time pricing regime are attributed to more efficient levels of commercial, industrial and residential demand response. In Enel X's view, the magnitude of these benefits will greatly depend on whether the framework is designed to incentivise participation. As has been made evident in the design of the "dispatchable demand" framework, onerous or unclear registration, participation and compliance frameworks will not see significant uptake. Frameworks that accommodate and incentivise participation by a broad range of consumers and business models are likely to see the greatest uptake.<br><br>As noted in response to question 2, the level of demand response will be far greater if load flexibility is separated from energy procurement and third parties were allowed to access the energy market directly. |
| Genesis Energy | Yes. We agree that a net benefit is likely, although we believe the SO should consider any adverse impacts on PPOs. |
| Mercury Energy | Yes. |
| Meridian Energy | We are not aware of other sources of benefit or cost, we are not in a position to comment on the assumptions made in the assessment. |
| MEUG | MEUG remains satisfied implementing RTP will be beneficial. The analysis in paragraph 6.21 on the breakeven industrial demand response, if that were the only benefit, being 16MW, is a useful cross check.<br><br>In the base case the ratio of the PV demand response benefits to the PV demand response costs for commercial and industrial (C&I) consumers is approximately 5:1. The ratio[3] for residential consumers is approximately 3:1. The cost-benefit-analysis result that the benefit relative to costs of demand response by C&I consumers is likely to be greater than that in the residential sector is consistent with MEUG's expectations and supports our view the focus of early adoption of RTP should be in the C&I sectors.<br><br>While MEUG is optimistic that technology coupled with the best set of code changes will realise the full potential of RTP over time, we are unsure whether the assumption in the cost-benefit-analysis that the full expected uptake will occur as soon as RTP goes |

[3] PV C&I demand response benefits to costs is \$48m/\$9m = 5.3. For residential consumers the ratio is \$23m/\$8m = 2.9.

| Q19. Do you agree with the cost-benefit assessment? In particular: – what (if any) other sources of benefit should be included in the assessment? – what is your view on key assumptions, such as the level of improved demand response enabled by RTP? – what (if any) other sources of costs should be included in the assessment? Please explain your reasoning. | |
|---|---|
| | live. We expect there will be many early adopters with other potential participants waiting to see if any wrinkles in the software and or code need to be fixed before committing. Such issues with the Code were observed when DD was first implemented. |
| Transpower | Yes. |
| *Trustpower* | *1.1.4 Trustpower's response to the particular questions (1-21) in the Paper is in the affirmative.* |
| IEGA, NZWEA, Orion | [No response to this question] |

| Q20. Do you agree with our assessment of alternatives? If not, why not? | |
|---|---|
| Contact Energy | No comment. |
| Enel X | Yes. Enel X agrees that the current proposed real time pricing design is better able to achieve the desired objectives than the alternatives presented in section 6.23. |
| Genesis Energy | Yes. |
| Mercury Energy | Yes. |
| Meridian Energy | Yes. |
| MEUG | Agree in relation to dispatch-lite.<br>Note in paragraph 3 of the opening page of this submission we raise concern with another related aspect of the overall RTP proposal, namely the lack of post-RTP DD participants being able to use ramp rates whereas generators will have that option. |
| Transpower | Yes. |
| *Trustpower* | *1.1.4 Trustpower's response to the particular questions (1-21) in the Paper is in the affirmative.* |
| IEGA, NZWEA, Orion | [No response to this question] |

| Q21. Do you have any comments on the drafting of the proposed Code amendment? | |
|---|---|
| Contact Energy | Regarding the gate closure definition in Part 1, amend clause (b) to 1 trading period to enable more efficient dispatch as per our general comments in note 4 ‘Reduction in gate closure to 1 Trading Period’ above.<br>Regarding 13.58AA, we have concerns about having the scarcity price and reserve shortfall values in the code if they need to be altered in a timely manner based on the review mentioned in Q16. As per our response in Q12, Contact’s preference is for the higher price CVP values listed in clause (3). We also support a review of the price and quantity values in clause (2).<br>Regarding 13.58AB, as per our response in Q16 the review time should be no later than 1-2 years initially.<br>Regarding the removal of 13.71, are all of these inputs mentioned elsewhere in the code i.e. revised offers and generator ramp rates? If not then these need to be reinstated.<br>13.182A mentions interim prices to 14:00 1 day following the trading day, what is the reasoning for this delay as we were of the opinion that the real time price was the final price? |
| Enel X | No. |
| Genesis Energy | Not at this time. |
| Mercury Energy | No. |
| Meridian Energy | The proposed drafting of clause 13.173C still limits the discretion of the Authority to decide whether a pricing error has occurred. We pointed this out in our earlier submission and had assumed it was corrected given the assurances in the workshops that “the Authority will decide after considering advice”.<br>The drafting in question is the words highlighted below, which imply that the Authority must reject a pricing error claim if the system operator has advised it to do so, i.e. if the system operator advises that there is a pricing error then the Authority would be unable to reject the error claim. Meridian would like to see the drafting tightened so that the Authority is clearly able to accept or reject, at its sole discretion, an error claim and is not bound by the advice of the system operator.<br>**13.173C Authority to decide whether pricing error has occurred**<br>(1) No later than 2 **business days** after receiving a report from the **system operator** under clause 13.173(1)(f), the **Authority** must either—<br>(a) decide whether a material **pricing error** has occurred; or |

| Q21. Do you have any comments on the drafting of the proposed Code amendment? | |
|---|---|
| | a) decide whether a material **pricing error** has occurred; or<br>(b) if the **system operator** has advised the **Authority** to reject a claim, reject the claim. |
| MEUG | Not at this stage. We may have comments once we see the consolidated proposal following this consultation round on the remaining 3-design elements. |
| Transpower | Yes. In the body of this submission we have:<br>- Proposed re-drafting of clause 13.69AAA to be more specific about the nature of the demand data required to be provided from the grid owner's meters.<br>- Identified that the level of reliability required from grid owner's supporting infrastructure is not addressed by the proposed Code drafting.<br>Suggested that where RTP will no longer require specific data or information for pricing processes, the Authority should establish what other industry processes are reliant on that data or information before removing obligations on participants to provide it. For example, the obligation for embedded generators to provide injection information to the grid owner is removed by RTP, but we use that information to create gross load forecasts for system planning. The injection information provision may also be needed for anticipated future policy under Additional Consumer Choice of Electricity Services (ACCES). |
| *Trustpower* | *1.1.4 Trustpower's response to the particular questions (1-21) in the Paper is in the affirmative.* |
| IEGA, NZWEA, Orion | [No response to this question] |

## Section 2 Comments on issues other than specific consultation questions

Text in square brackets [] has been added by the Authority to improve clarity.

| General support (or otherwise) for RTP | |
|---|---|
| *Contact Energy* | *Contact supports the Authority's view that RTP will result in improved price certainty and more actionable market outcomes. This will ensure that participants are better informed to react to the real time price, subject to there being no unexpected outcomes.* |
| *Enel X* | *Enel X is supportive of a move to real time pricing. By more accurately reflecting the prevailing market conditions, real time pricing will enable market participants to make more efficient decisions; promote greater transparency of price responsive load and generation; and bring about greater market efficiency.* |
| *Genesis Energy* | *We look forward to continuing to engage on this important work programme and its core design elements so that ultimately, real-time pricing (**RTP**) can deliver more certain and actionable prices for generators and purchasers to the net benefit of consumers.* |
| *NZWEA* | *2. NZWEA wishes to confirm its support for the RTP project and the introduction of dispatch-lite as proposed.*<br>*9. While the Association did not submit on the 2017 RTP consultation NZWEA considers the project a significant development for the electricity sector in enhancing the trading of electricity and that the proposed dispatch-lite changes support the achievement of the stated objective of ensuring spot prices more accurately reflect prevailing conditions on the power system.* |
| *Orion* | *2.1 Some important details of the RTP approach remain unclear,* |
| *Transpower* | *Thank you for the opportunity to submit to the Electricity Authority's consultation Remaining elements of real-time pricing published 19 March 2019. We agree with the Authority' expectation RTP will unlock significant benefits through much more reliable price signals for consumers and generators to act on. Consequently, we strongly support the project and its objective to "make spot price signals more accurate and actionable for all decision-makers."*[4] |

[4] Authority Consultation Paper: Remaining elements of RTP March 2019, page ii

| General support (or otherwise) for RTP | |
|---|---|
| *Trustpower* | *1.1.3 Trustpower continues to support the Authority progressing the design of RTP arrangements and, in particular, is fully supportive of the proposed remaining design elements presented in the Consultation Paper.* |

| General support for dispactch-lite | |
|---|---|
| *Mercury Energy* | *Mercury considers that real time pricing has significant benefits for the electricity market independent of the inclusion of an expanded form of 'dispatch-lite' to include smaller-scale generation. We are pleased that the Authority has managed to obtain funding to ensure this important project can proceed to implementation. If the Authority proceeds with the inclusion of 'dispatch-lite' we would recommend further analysis be undertaken to fine tune the eligibility criteria and compliance requirements for distributed generation. The proposed methods for determining these features as currently outlined, leave much to the discretion of the System Operator which will create uncertainty for market participants. We would also like to see the proposed guidelines and policy statement on the compliance arrangements for 'dispatch-lite' circulated for comment ahead of their adoption.* |
| *NZWEA* | *2. NZWEA wishes to confirm its support for the RTP project and the introduction of dispatch-lite as proposed.*<br>*8. In this submission the Association therefore focuses on the revised "dispatch-lite" proposal as this element is most relevant to the wind industry and in particular enabling smaller scale electricity generation to cost effectively participate in the spot market.*<br>*10. NZWEA supports the expansion of dispatch-lite to include smaller-scale generation in addition to controllable demand. Doing so strengthens the RTP proposition including better accommodating future shifts in technology.*<br>*12. Increasing the opportunity to cost-effectively participate in the spot market should result in greater understanding of, and confidence in, how the market functions.*<br>*14. In summary the Association considers that to provide for future trends in distributed generation, and enable New Zealand's significant potential for smaller scale wind farm developments to be realised, it is important to have a model for spot market participation that is cost appropriate such as dispatch-lite.* |
| *Orion* | ***Dispatch-lite***<br>*17. We support the extension of the dispatch-lite concept to generation. This is because we agree that the location of generation (in front of or behind the meter) does not, of itself, change its impact on the demand that must be met by other generation. Whether inclusion of generation within dispatch-lite will make a difference to its appeal to participants remains to be seen.*<br>*18. As far as we can tell the only advantage a dispatch participant gets over a non-dispatch participant is an actual instruction, if* |

| General support for dispactch-lite | |
|---|---|
| | *dispatched. This is primarily an indication that the price is at or above the level that the participant is willing to reduce demand / increase generation. Alternatively, a participant could simply monitor dispatch prices in real time and make their own decisions outside any Code restrictions or obligations.* |

| Engagement groups | |
|---|---|
| *IEGA* | *The IEGA also notes the Authority's proposal to establish engagement groups to focus on specific*<br><br>*areas. We would welcome the opportunity to be involved in an engagement group if one is established in relation to distributed generation-lite or dispatch-lite.* |
| *Meridian Energy* | *Finally, we appreciated the commitment in the April workshop that engagement groups will be established to operate as a key interface between the project team and industry during the next three years. We would like to be involved in these engagement groups and look forward to understanding as early as possible how these groups will be formed and how they will operate.* |
| *Transpower* | *We also support the decision to use engagement groups to develop participant understanding as the project progresses. Transpower as system operator is committed to increased communications and reporting of the technical aspects of the real-time market, including how participants' information will be used in the price formation process.* |

| Demand forecast accuracy | |
|---|---|
| *Contact Energy* | ***1. Improved Demand Forecast for RTP***<br><br>*As mentioned in Contact's October 2017 submission, the accuracy of the System Operator (SO) demand forecast needs to be improved. Accuracy of the forecasted price is an important part of the success of RTP as the gate closure period (1 or 2 trading periods) means that market participants cannot react to price in real time. We recommend that the Authority's projects for RTP and improving SO demand forecast need to be progressed in parallel.*<br><br>*The proposed dispatch-lite product needs to incentivise the inclusion of the unscheduled demand shedding that currently occurs as this is a major cause of the existing forecast inaccuracy. The Authority should make demand bidding mandatory under the Code, and provide improved guidelines so that demand participants are not able to bonafide offers based on price. This product* |

| Demand forecast accuracy | |
|---|---|
| | *needs to incentivise the inclusion of the unscheduled demand shedding that occurs at present to ensure demand forecast accuracy.* |
| *Meridian Energy* | *In relation to the system operator's load forecasting:*<br>• *We are pleased to see the proposed move to bottom-up load forecast using ION meters as the primary input for short-term load forecasting.*<br>• *Real-time pricing and improvements to short-term load forecasting will give more certainty to demand side consumers that can respond in real-time. However, market participants that are subject to gate closure do not have that option. Therefore, the forecast schedules, and particularly the medium-term load forecast will need to be more accurate if there is to be any improvement in decision-making and greater efficiency as a result.*<br>• *We understand the system operator is looking at improvements to the medium-term load forecast.[5] We would appreciate the publication of an update on this work and stress again the importance of forecasting improvements in advance of the go-live date for real-time pricing.* |
| *Orion* | *2.2 The processes by which the supporting demand forecasts will be produced, maintained and interpreted will be particularly important.*<br>***Demand forecasting***<br>*6. Central to the process will be the various demand forecasts used by the system operator (SO), and the extent to which they are different. This is not directly part of the RTP project, but we note the reference to bottom-up short term forecasts based on ION metering. We submit that, in an environment of increased demand response, it is not the current metered quantity – however accurately measured - that is so important. Rather, it is how much demand response is 'included' (perhaps more accurately 'reflected') in the current metered demands. Is the system to be dispatched to meet a forecast based on metered demand, or a forecast based on what the demand would be were demand response added back. This is not a trivial exercise and it has not been explained how the SO is going to do it. We can safely say that if demand response is zero, everything should be fine. But the RTP project is founded – from a cost-benefit perspective at least - almost entirely on materially increased demand response, so how this is modelled and managed becomes critical.*<br>*7. Related to our point below about distributor switching between GXPs, it is conceivable that this could create some issues for the SO in understanding what it is looking at. It may be more sensible to view parts of the grid where switching between GXPs is* |

[5] https://www.ea.govt.nz/dmsdocument/23890-tas073-evaluate-options-to-improve-the-system-operator-load-forecast and http://www.teslaforecast.com/wp-content/uploads/2015/07/MTLFTrialReport-TESLA-28April2017.pdf

| Demand forecast accuracy | |
|---|---|
| | *possible in the same way that "blocks" of generation are treated: it is the aggregate that is important rather than the components.* |

| Other comments | |
|---|---|
| *Contact Energy* | *However, we recommend that the Authority conduct thorough testing of past stressed market conditions to ensure market outcomes under RTP are as modelled or predicted.*<br><br>***3. High Spring Washer Situations (HSWS) under RTP***<br><br>*We believe the Authority needs to undertake further work to understand the impact HSWS will have under RTP. HSWS are highly impacted by minor changes to modelling assumptions, and can have vastly different economic outcome. Whilst the current approach to slightly relieve constraints during the interim price period helps to address this, our understanding is that no such mechanism will be used under RTP.*<br><br>*Participants need to be assured that there will not be any unexpected outcomes under HSWS. We recommend existing processes and changes be reviewed to ensure that these type of outcomes do not occur; for example, that scarcity price signalling should be directed at the correct nodes to manage the situation. Past HSWS should be tested to give confidence to the market that RTP is robust under these scenarios.*<br><br>*Given the potential for more volatile locational pricing under RTP, we anticipate greater scrutiny will need to be placed on Transpower to ensure that certain planned outages occur at low risk periods, or alternatively that these outages are cancelled if scarcity prices are consistently signalled when all known market solutions have been exhausted. A further question is what will occur in RTP when the prices are negative under a HSWS?* |
| *Genesis Energy* | *We also support the Authority to progress its project to make hours-ahead price forecasts more accurate, which will promote efficient demand response and generation scheduling.* |
| *IEGA* | *This submission is focused on the new proposals for dispatching distributed generation – referred to as distributed generation-lite. We appreciate the Authority's work on enabling distributed generation to opt-in to a 'lite' dispatch process following our feedback on the initial real-time pricing proposals.* |
| *Meridian Energy* | *In relation to market system outages:*<br><br>• *We appreciate the further work that has been done to explore back-up systems to avoid market system outages. It is* |

| Other comments | |
|---|---|
| | *helpful that as part of this the system operator and Authority published recent outage statistics – 16 days with an outage in the 15 months from November 2016 – January 2018.*<br>• *We are not convinced by the conclusion that the market impact of such outages does not justify the capital and ongoing cost of providing an 'always-up' market system. The amounts of money exchanged through the market system mean the risks and costs of any outage are potentially high and we have not seen any analysis that directly compares the cost of an 'always-up' system and the potential costs to participants as a result of outages.* |
| *MEUG* | *3. We have a concern that the existing Dispatchable Demand (DD) participant will be unable to comply with the shorter time frame between receipt of dispatch instructions to decrease demand under the proposed post-RTP DD regime where they are dispatched using the dispatch schedule rather than the Non-Response Schedule Short (NRSS). In our submission of 10th October 2017 in response to question 13, we asked if inclusion of ramp rates for DD could be considered. It is disappointing that suggestion has not been considered in this consultation. It seems anomalous that once RTP is implemented generators will continue to have the benefit of ramp rates but DD participants, in all other respects with the same obligations as generators, will not.* |
| *NZWEA* | *3. One of the Association's three key areas of strategic focus is to expand the opportunity for wind development to enable community and industrial projects including wind's integration with other technologies.*<br>*4. Studies undertaken by the Parliamentary Commissioner for the Environmenti confirm that large scale wind farms can only ever occupy a small portion of a country's wind locations. Microclimates which have funnelling or hilltop attributes are very favourable for small scale wind projects.*<br>*5. While internationally small-scale community owned wind farms are a growing sector to utilise available wind resource, increase local energy independence and reduce carbon emissions New Zealand has yet to realise the potential of smaller scale developments.*<br>*6. It is also acknowledged that geographical diversity for wind farms reduces the impacts of intermittency by being exposed to different weather patterns.*<br>*7. As New Zealand's electricity system develops, with an increasing level of intermittent renewable generation, it is important that market and trading arrangements enable greater market participation of both small-scale generation as well as dispatchable demand.* |
| *Orion* | ***Reflections on our previous comments***<br>*4. It appears to us that few if any of our comments on the August 2017 paper have been considered or responded to in this paper. We discuss some of these under the following headings.* |

| Other comments | |
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| | ***The end-to-end process and short-termism***<br>*5. It remains unclear to us when precisely final prices are to be produced, and how much before real time they will be known or what determines how long a particular set of RTPs will persist. We suspect the combination of these things will significantly reduce the chances that the prices are in fact more actionable. We remain concerned that a solely short term dispatch focus is missing a potential opportunity to re-think how consistent this is with optimisation over a longer time frame.*<br>***Distributor involvement in dispatch and existing load management***<br>*8. Distributors are involved in or influence the wholesale market in two key ways:*<br>*8.1 They are agents of the SO with respect to load shedding (if this is required), and*<br>*8.2 They - occasionally at present - influence wholesale market outcomes via load management.*<br>*9. Regarding load shedding we are not sure how this will work in real time. It appears that the 'dispatch' of load shedding instructions will come out of a pricing run that produces a scarcity price, but what is being 'dispatched' here is not an offer or a bid, but a distributor's (or multiple distributors') ability to turn load off in real time. These are not the same things. We note:*<br>*9.1 There may well be demand / generation response that has also been dispatched (or responds without instruction) but its operation is confounded by the distributor actions – for example if it happens to be on the same feeder. This could lead to undershooting of the required response.*<br>*9.2 Where demand / generation response is not connected to the shed feeder, there could be overshooting.*<br>*9.3 In energy shortage situations and grid constraint situations there is likely to be some notice that the situations are emerging. This may not happen under RTP. Aside from operational matters, this will mean there is much less opportunity for customers to prepare for an outage. This will in general increase (worsen) the economic impact.*<br>*9.4 The 'lumps' of load available to distributors to shed may not match up very well with the amounts required by dispatch, and are not always even known in real time. How will the SO know what to ask for, and of whom? How will it monitor what actually happened? If the scarcity pricing situation continues, should the distributor move to rolling outages?*<br>*10. Regarding distributor load management, and as explained in previous submissions, this – at least in Orion's case and in the upper South Island – involves managing load to a limit – a maximum aggregate demand across the region. When this management is active, pretty much any other form of demand response is effectively, and automatically, negated: if some load is turned off, a similar amount of other load will be turned on and vice versa. Probably the main way that this impacts on RTP is via load forecasting, as load management primarily changes the shape of profile across the day. A forecast based on a typical day profile is likely to be very inaccurate.*<br>*11. We note the depiction of distribution networks as 'clouds' in the paper (Figure 1). This is fine in context, but there needs to be fuller acknowledgment that distribution networks have their own constraints and operational imperatives. The actions of wholesale* |

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| | *market participants and demand response players may from time to time push those constraints to the point where offsetting action is required by distributors. This will change wholesale market outcomes.*<br>*12. Going forward, distributors may themselves have many more arrangements in place to procure further demand response as the number of DERs deployed increases. This certainly seems to be anticipated by recent reports by IPAG and ENA's STWG. The coordination of the needs that any given demand response is being applied to meet will be very important in those cases.*<br>*13. Finally, the attributes of potential new DER-based demand (or generation) response needs to be considered. In particular where this involves storage (batteries, EVs) then it will, as does existing storage in the form of hot water:*<br>*13.1 Have a very low SRMC, with this increasing as the duration of 'dispatch' increases, and*<br>*13.2 Display the characteristic that the longer it is dispatched the higher the restorable load across multiple DERS, due to reduced diversity.*[6]<br>***In summary***<br>*14. On all of these topics [the end-to-end process and short termism, demand forecasting, and distributor involvement in dispatch and existing load management] we suggest that the Authority and the SO spend a good deal of time over the next few years detailing the processes involved, and how the SO will respond under various scenarios. We suggest that a significant number of simulations need to be run, for example of various combinations and levels of bid and unbid demand response.*<br>*15. To the extent that distributor load management is a factor, we are happy to work with the Authority and the SO so that they understand this.*<br>*16. One area of particular interest to distributors is the nature of the arrangements that will be used when scarcity prices are to be used but it is not a formal public conservation campaign. Will distributors be required to switch off customers even if a lower cost response is available to them? What units of load shedding will be called upon?* |
| *Transpower* | ***Real-time price formation relies on quality data from meters***<br>*Under RTP, real-time prediction of demand will be a critical input to final price formation, with the primary data input being metered demand at each GXP.  Currently the system operator's real-time demand prediction is a top down method using metered generation data as the primary input.*<br>*For the proposed new approach for RTP, which we support, the system operator will take the grid owner's net demand values* |

[6] To explain using the hot water example: when water heating is turned off, not all connections show a reduction in load as they may have already reached the desired temperature and be off anyway. As time passes without supply, the number of fully heated cylinders inevitably reduces, so that when supply is restored the increase in load will be higher than the original decrease.

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| | *from its ION meters, and (when necessary) use data received from offered embedded generators to create a gross demand prediction in real-time.*<br><br>*With that new context we make the following Code-related points.*<br><br>***The nature of demand data to be provided should be defined in the Code***<br><br>*The Code should define that the demand data that is provided by the grid owner's meters is for net demand. Accordingly, we propose drafting to better convey policy intent for providing real time demand values from the grid owner's assets:*<br><br>*Transpower proposed clause 13.69AAA*<br><br>***13.69AAA Grid owner to provide real time demand values to system operator***<br><br>*Each **grid owner** must, to the extent practicable, use its <u>grid revenue meters</u> to provide to the **system operator** real-time <u>net</u> **demand** values (in **MW**) for each of its **GXPs** for the purpose of ~~that are required by the **system operator** to calculate the expected profile of **demand** under~~ clause 13.69B (3)*<br><br>***Reliable, accurate ION meter data is dependent on supporting infrastructure***<br><br>*Under RTP the grid owner's SCADA infrastructure will play a critical role in delivering reliable, accurate data from the ION meters to the system operator's market systems in real-time. The level of reliability required from the grid owner's supporting infrastructure is not addressed by the proposed Code drafting. We consider consequential investment in grid owner supporting infrastructure <u>may</u> be required, along with a mechanism to allow the grid owner to recover the cost of that investment.*<br><br>*During the next phases of the RTP project we expect the interface between grid owner and system operator systems and processes will be considered in detail. For example, how to configure control and monitoring systems to flag when potential metering issues are detected and/or trigger a switch to back-up metering systems.*<br><br>***RTP changes removing data and information obligations may have adverse implications outside pricing processes***<br><br>*In our view, proposals to remove data and information obligations attached to the existing pricing process may have adverse consequences for other existing and potential information processes. For example, the obligation for embedded generators to provide injection information to the grid owner is removed by RTP, but we use that information to create gross load forecasts for system planning. The injection information provision may also be needed for anticipated future policy under Additional Consumer Choice of Electricity Services (ACCES).*<br><br>*Where RTP will no longer require specific data or information for pricing processes, the Authority should establish what other industry processes are reliant on that data or information before removing obligations on participants to provide it.* |

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| | ***Consequential change to the FTR market and LCE allocation***<br>*We note the change signalled by the RTP presentation[7] for Loss and Constraint Excess (LCE) to be allocated from dispatch schedules, which will require consequential change to Financial Transmission Rights (FTR) market systems and processes. We consider the changes are an opportunity to seek operational efficiencies associated with allocating LCE for FTR settlements, and allocating residual LCE to market participants.*<br>*With 3 new hubs added in June 2018 the FTR grid now more closely approximates the whole grid and LCE across the FTR grid is close to 90% of all LCE. We consider an efficient consequential change would be for the clearing manager to allocate LCE for FTR settlements to the FTR manager, and residual LCE directly to purchasers alongside other market reconciliation and clearing processes.*<br>*In our view the growth of the FTR market means Transpower's involvement in allocating residual LCE is unnecessary and inefficient.*<br><br>*In our role as system operator we look forward to developing and implementing RTP and are confident we have the resource and expertise required to do so. We note Transpower "may have limited ability to respond to any other proposals for material system change that might arise in parallel."[8]*<br>*Finally, we commend the positive engagement between the Authority and system operator to date on this substantial and exciting project, and look forward to continuing collaborative development between all parties going forward.* |

[7] RTP presentation (slide 13) states "Loss & constraint excess apportioned from dispatch schedules"
[8] Transpower submission to Authority consultation on RTP, October 2017.