Real-time pricing consultation 2017

Summary of submissions

19 March 2019

Summary of submissions on our August 2017 real-time pricing consultation

1.1 We published our proposed design for real-time pricing in the wholesale spot market (RTP) in our *Real-time pricing proposal* consultation paper on 1 August 2017, for an eight-week consultation. We subsequently extended consultation to 10 weeks, to allow interested parties more time to consider our detailed responses to questions.

1.2 Submissions closed on 10 October 2017. We received 18 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/#c16609.

Table 1: List of submitters on our August 2017 consultation

Submitter	Role
Contact Energy Limited Genesis Energy Limited Mercury Energy Limited Meridian Energy Limited Trustpower Limited	Large gentailer
Flick Energy Limited	Smaller retailer
Independent Electricity Generators Association (IEGA) Incorporated	Smaller generators
Electricity Networks Association Orion NZ Limited Powerco Limited Vector Limited	Electricity distributor or representative body
Major Electricity Users' Group (MEUG) New Zealand Steel Limited Pacific Aluminium Winstone Pulp International (WPI) Limited	Consumer or representative body
NZX Limited	Service provider
Transpower NZ Limited	Grid owner and system operator
EnerNOC Incorporated	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 91.

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.

Q1. Do you agree with the broad principle of using dispatch prices to determine final prices? If not, please explain your reasoning.	
Contact Energy	Yes provided the inputs are accurate. This requires an upgrade to the System Operator's load forecasting tool (used in the schedules) and all demand capable of being shed (including load control from lines companies) being able to be bid into the schedules. In the absence of this the forecast price will be no more accurate than it is currently. If parties are able to take action based on prices, this will result in more efficient decision making by participants.
Contact Energy	***1. More accurate forecasts required*** *Contact supports market participants accessing timely and reliable information on the prices they will pay or receive for their spot market transactions. While we are generally supportive of the direction of this paper, in order for the proposal to achieve its objectives of creating more certainty and improving the ability of parties to take action and make efficient pricing decisions, we think the accuracy of load forecasts also requires addressing. It appears that generally this inaccuracy relates to lines companies curtailing peak load to reduce transmission costs. Whilst this is an accepted practice it does not appear to be covered by the Code. If this practice was covered by the code to require load curtailment to be signalled in advance, Transpower would be able to provide a superior forecast and this inaccuracy could be reduced.*
EnerNOC	Yes, more cost reflect the final prices are of actual system operation will improve the information available for parties to make informed decisions.
EnerNOC	*EnerNOC believes there are a number of benefits to be gained from moving to real-time pricing. For example:* *1) Aligning prices with network conditions at that point in time* *2) Better forward information for participants to make short-term operational decisions* *However, EnerNOC is concerned with some areas of the Authority's current proposal. Primarily the concerns are the use of time-weighted average dispatch prices to form final prices, lack of flexibility and onerous compliance obligations for dispatchable demand participants and non-conforming GXPs being disadvantaged over conforming GXPs.*

Q1. Do you agree with the broad principle of using dispatch prices to determine final prices? If not, please explain your reasoning.	
Flick Energy	Yes. Flick is supportive of making spot prices more actionable and efficient and agrees that that using dispatch prices to determine final prices is the right broad principle. Flick agree with the Authority's statements at paragraph 2.6 that the current arrangements do not allow participants to make the most efficient demand response, generation, or trading decisions. Flick is particularly supportive of changes to allow the best to be made of other technology advances. As the Authority has identified, price certainty is an enabler of battery, communication or automation devices. The Authority highlights at 2.10 that New Zealand is unique in terms of the two day delay with pricing. Removing this delay would align pricing with modern consumer expectations. Flick agrees with the Authority's design philosophy that final pricing should align with the system operator's real-time dispatch process as far as possible. Flick is supportive of using dispatch schedules to generate dispatch prices (derived from the interaction of generation and demand bids in real-time). Flick note that by including load assigned default scarcity values in pricing– means that 'infeasibilities' and other provisional pricing would no longer occur. Flick agree with the Authority's statement at 3.6 that these provisional pricing situations occur at times when price certainty is of particular importance to participants.
Genesis Energy	Yes, subject to the following comments: While Genesis understands the justification for calculating prices based on a 30-minute trading period, we do wonder if this will be out of step with the pace with which technology, computing power and the electricity market is moving. We would like to see the Authority commit to leaving the door open for five-minute trading periods in the future.
IEGA	The IEGA agrees that dispatch prices should, where possible, determine final prices. However, it remains unclear how final prices will be discovered as it appears the dispatch process for DG (and similar energy storage devices[1]) has not been specifically considered in the proposed design. As illustrated in the diagram below DG owners sit in a unique position relative to other participants.

[1] However, we note that the recent Q&A responses indicate battery use is being contemplated for dispatch and price setting

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	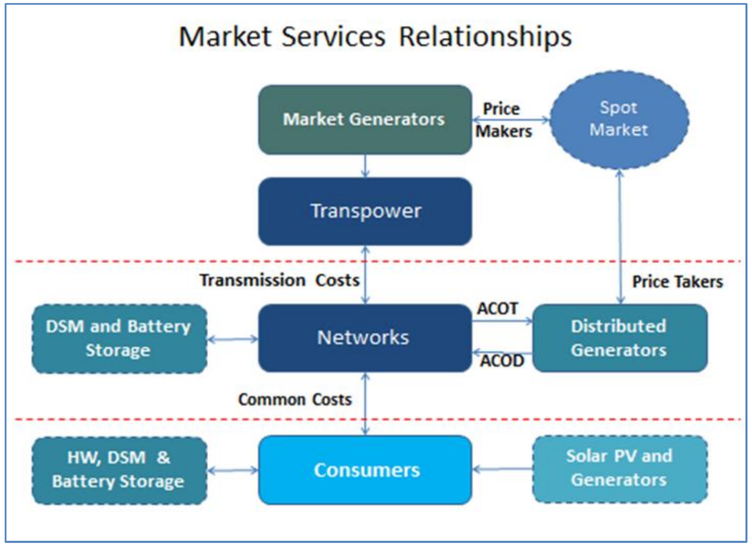 The RTP proposal includes specific provisions for consumers at ICP meters and for directly connected consumers to bid into the spot market using either the Demand Dispatch or Dispatch-lite mechanisms. A correctly designed market should ensure transparency, information symmetry and price discovery for all participants. The proposal is unclear as to how DG owners can actually participate in the proposed RTP spot market. This is important as Transpower[2] estimated DG supplies about 8% of peak demand. Demand response was estimated to reduce peak demand by the about the same amount. This total 'response' to peak transmission and spot pricing respectively is about the same as the scarcity price blocks for forecast demand proposed in the Consultation Paper[3] - at 5% and 15% of demand. The IEGA has the following concerns: **DG is currently included on the Demand-side** The System Operator currently creates a net demand forecast at each GXP. This assumes both DG and demand response (DR) volumes are netted off demand based on historic practices. Under the RTP process, load forecasts must be based on gross GXP demand forecasts. Both DG and DR supply resources,

[2] Transpower's TPM Submission July 2016, Appendix G by Scientia Consulting at http://www.ea.govt.nz/dmsdocument/21133
[3] Table 1, page 19 of Consultation Paper

Q1. Do you agree with the broad principle of using dispatch prices to determine final prices? If not, please explain your reasoning.	
	such as batteries, should have the option of being able to participate in the price discovery process – if they want to. This would require a more fundamental change in the RTP price setting process than currently contemplated – i.e. more a bottom up than a top down process. This would also be more accommodating of rapidly changing technologies and potential new services. It is not appropriate to just ignore or overlook DG volumes in the design. **Is DG to be on the Generation side of spot market?** DG has historically delivered up to 11% of total electricity supply. We believe DG would make a material contribution to price discovery and suggest the system be designed so that DG can: • be allocated to the supply side of the market as a generation bid; and • bid as Dispatch-Lite (ie. the same arrangement as for load); and • for non-conforming DG, be allocated scarcity pricing (consistent with load that is non-conforming). **Investment signals from nodal prices** The recent decision by the Authority to remove ACOT payments to DG that does not contribute to grid reliability has eliminated the incentive for DG to respond to peak demand. Further, the Authority opined that DG would respond instead to nodal spot prices to ensure the highest possible revenue. The overall intention of the RTP appears to be to achieve a reduction in average spot prices through demand-side bidding. The following extract highlights this focus: 4.21 This analysis indicates that if improved demand response is the sole benefit of RTP, it would need to increase by approximately 10 MW to breakeven under the base case cost estimates. This level of improvement in demand response appears relatively modest in overall terms, as it represents slightly more than 0.1% of total system demand in peak periods. The design of RTP seems to be highly influenced by improving short run marginal cost efficiencies. Clearer options for DG and DR to participate are needed to adequately incentivise or compensate for being involved in dispatch (these options combine at more than 20% of peak capacity). Otherwise the price discovery and investment signals would appear to be severely compromised.
Mercury Energy	Yes
Meridian Energy	Yes

Q1. Do you agree with the broad principle of using dispatch prices to determine final prices? If not, please explain your reasoning.	
MEUG	Agree with the broad principle.
NZX	Yes
Orion	Yes we agree with the broad principle. However, we believe a number of approaches align with the broad principle. More generally though, actionable prices must encompass the time it takes to carry out the actions. If the nub of the problem is actually that forecast prices are an unreliable indicator of final prices, then producing final prices more quickly simply brings forward the disappointment.
Orion	***Prices should reflect dispatch*** 14. *That prices should reflect dispatch is certainly reasonable on the face of it, and will probably result in reasonable outcomes most of the time. We note that final prices do currently reflect actual dispatch even if it takes a while to work out exactly what that was.* 15. *However, we note that there will still be variances between the dispatch schedule, and what actually happens in real time, and how the system operator (SO) responds to these over time will be critical.* 16. *The dispatch process is inherently short term, which it must be to manage the system in real time. However, that does not mean that actions in one dispatch period do not impact on actions and available resources in later periods. We see some risk that the proposal makes dispatch even more myopic than it currently is, and perhaps even blind to circumstances and opportunities. We also see some risk of instability if and when there is material un-bid demand response that is not knowable by the SO as this could create material, and greater than present, divergence between what was expected when prices are set and what actually happens.* 17. *As we submitted in relation to demand forecasting,*[4] *consideration should be given to whether the optimisation period needs to be changed. We think that a day is a more appropriate period for optimisation, particularly with respect to existing and possibly increasing use of storage to manage demand in real time.* 18. *At the Wellington workshop on 24 August a suggestion was made that price could become a variable in the demand forecast. While that sounds reasonable, we expect there are a few significant issues to work through if it is to be*

[4] Orion New Zealand Ltd, Submission on spot market review, 5 May 2015, p8 and 9.

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	implemented. It does, however, highlight the potential wider issue of how the SO will factor un-bid demand response into its forecasts. 19. *More generally the relationship between the demand forecast that drives dispatch, and the demand forecast that drives forecast prices needs to be well understood.* 20. *Reassuringly though, the paper sees dispatch as pragmatic (para 3.30). We believe this principle could have wider application when thinking about how prices are set, and this is discussed further in the next section.*
Pacific Aluminium	Yes. The current lag between 'real time' prices and settlement prices is a disincentive to participate in demand management. RTP should provide a greater degree of certainty when making demand management decisions compared to current indicative prices.
Transpower	Yes. Settlement on dispatch prices in real-time should improve participant confidence in accurately responding to wholesale market spot prices. More accurate consumption decisions should result in improved allocative efficiency and promote the Authority's statutory objective.
Transpower	*We consider industry submissions to date demonstrate a good level of support for the real-time pricing concept.*[5] *Although we are not a participant in the spot market, we expect settlement on dispatch prices in real-time will improve participant confidence in responding to wholesale market spot prices and promote the Authority's statutory objective.*
Trustpower	Yes, we generally support the Authority's design philosophy of aligning final prices with the system operator's real-time dispatch process. We appreciate that the proposal seeks to achieve this goal while minimising complexity and system costs. We consider that in the case of spring washers the Authority should consider incorporating a pragmatic limit on the price ratios into the design to mitigate the risk to retailers. For example, a limit of 5x the highest cleared generation offer at any node during a spring washer event, would protect retailers against incurring significant additional costs under the new RTP arrangements. We note this could be applied ex-ante and therefore be consistent with the RTP arrangements being proposed. We would be happy to discuss this matter further with the Authority. More broadly, we recommend that the Authority undertake a post-implementation review of the proposed RTP arrangements, within a reasonable period following implementation, e.g. 2-3 years later. We have outlined a number of matters that should be

[5] Authority's decision paper *Real-time pricing options* August 2016 "*Thirteen of the fifteen submissions supported further work specifically on option B in preference to the other identified options*" [paragraph 13]

Q1. Do you agree with the broad principle of using dispatch prices to determine final prices? If not, please explain your reasoning.	
	explicitly considered as part of this review in our responses to the Authority's questions in this Appendix.
ENA, NZ Steel, Powerco, Vector, WPI	[No response to this question]

Q2. Do you agree with using the time-weighted average of dispatch prices to calculate prices for a trading period? If not, please explain your reasoning.	
Contact Energy	Yes. As the Authority states in 3.10 (iv) the volume weighted price would be more accurate but it would be difficult to forecast these prices in the Forward Market as they are based on demand and generation volumes at each node. As a general rule we think that when plant is dispatched it should always get paid at least its offer price.
EnerNOC	No. If the goal of moving to a real-time price is for prices to reflect current system operation, allowing consumers to make informed decisions, time-weighted average prices will not completely achieve this. EnerNOC is concerned that a time-weighted average methodology of dispatch prices for calculating final settlement prices will lead to price signals being diluted and cross subsidies occurring within the market. Constraints within the market at times are very steep and short-lived. Prices must clearly reflect the cost of these constraints, allowing efficient investment decisions. Time-weighted average prices will not deliver this clear price signal and consequently lead to inefficiencies within the market. Below is an example of a system with three GXPs and two generation units. Generator 1 offers 150MW at $100/MWh generator 2 offers 10MW at $200/MWh. Under volume-weighted average, the assets GXP 2 and Generator 2 providing the peak service for the system are compensated on an area under the curve basis for the service they are providing to enable the system to peak at 160MW. GXP 3 is the causer of this peak and as a result bears the associated costs. While the total cost for the system is greater under volume-weighting, this is a result of the offer stack having a hockey stick shape. *[EnerNOC includes charts here in their submission. These are included on page 108].* Furthermore the proposed time-weighted average methodology will lead to a price that is not ex-ante for the first 25 minutes (or until the last dispatch instruction is issued) within a trading period. What will be provided is a price that increases in certainty as time progresses towards the end of the trading period.
EnerNOC	***1 Dispatch price averaging method*** *EnerNOC is concerned that a time-weighted average methodology of dispatch prices for calculating final settlement prices will lead to price signals being diluted and cross subsidies occurring within the market. Constraints within the market at times are very steep and short-lived. Prices must clearly reflect the cost of these constraints, allowing efficient investment decisions. Time-weighted average prices will not deliver this clear price signal and consequently lead to inefficiencies within the market.* *Furthermore the proposed time-weighted average methodology will lead to a price that is not ex-ante for the first 25 minutes (or until the last dispatch instruction is issued) within a trading period. What will be provided is a price that increases in certainty as time progresses towards the end of the trading period.*

Q2. Do you agree with using the time-weighted average of dispatch prices to calculate prices for a trading period? If not, please explain your reasoning.	
	EnerNOC understands that there are a number of complexities involved with moving to what we view as a more cost reflective pricing method, these been: *1) Using a volume weighted mean of dispatch prices to calculate final prices, or;* *2) Aligning settlement period with dispatch schedules removing the need for an averaging method to be used* *The Authority has stated that under the current proposal there is not anything that will inhibit the progression to either volume-weighed prices or a shortened settlement period to better align with the dispatch schedules. However, EnerNOC is concerned that if these options will be ruled out simply on the merit that they are overly complex and as a result will be too costly with insufficient analysis and investigation.* *EnerNOC recommends that the Instantaneous Reserves (IR) price should be calculated using a volume-weighted average approach as it is not impacted by the major restrictions that are seen in the energy market, these being;* *1) Formal risk products currently offered at a limited number of nodes, volume weighted energy prices would lead to the inability for some participants to affectively hedge their position* *2) Metering data of sufficiently granular level for settlement* *Volume-weighted prices will insure that participants are paid/pay appropriately for the area under their demand/supply curve. As for the IR market it will insure a better reflect the island based locational value of IR and allow the IR market to act as a test bed for moving the energy market to a more cost reflective averaging method or settlement period.* *EnerNOC recommends that the Authority should make it a priority to match settlement period with dispatch period once the RTP market is implemented.*
Flick Energy	Yes. Time-weighted averages appear to be the best option to calculate prices. It would also be a positive outcome if the expectation is that time-weighted averages are not expected to require changes to other parts of the market -the FTR or futures contracts.
Genesis Energy	Yes, subject to the following comments: Genesis would like to see a transition to volume-weighted dispatch prices in the future, as per section 3.12 of the consultation paper.
Mercury Energy	Yes

Q2. Do you agree with using the time-weighted average of dispatch prices to calculate prices for a trading period? If not, please explain your reasoning.	
Meridian Energy	Yes
MEUG	Agree using time-weighted average of the six 5-minute dispatch prices (where updated every 5 minutes[6]) to calculate the final price in a trading period (TP) because that is the most pragmatic approach. We think volume weighted is a better approach but accept practical limitations. Even better would be TPs of and final prices every 5 minutes; that also has practical limitations at this stage.
NZX	Yes To support this process the list of published dispatch schedule information provided in Schedule 13.3B should include the start time for each dispatch schedule.
Orion	Yes. As an aside, the paper would have been clearer if the examples in Figures 3, 4 and 5 had not all been five minute intervals, since there is no difference between time weighted and arithmetic averages in such cases.
Pacific Aluminium	Yes
Transpower	Yes. The time-weighted approach to price-formation is • consistent with the approach to reconciliation and clearing of volume, and • lowest cost with least change to implement.
Trustpower	We consider that at this time a half hour settlement arrangement should be maintained. As a result we support the proposed use of a time-weighted average of dispatch prices to calculate the price for a trading interval at each node. We however note that under the proposed half hourly arrangement, there can still be potentially significant fluctuations between five minute prices which may make decision making difficult. There could be value in the future in aligning the approximate five

[6] MEUG notes the RTD price will only be updated during the TP if a change is needed, so theoretically the SPD solution for the first 5 minutes could remain for the whole TP.

Q2. Do you agree with using the time-weighted average of dispatch prices to calculate prices for a trading period? If not, please explain your reasoning.	
	minute dispatch periods with the settlement period, similar to the current proposal being considered in the NEM to move to 5 minute settlement. This would align the physical electricity system with the price signal that was provided and potentially lead to further efficiency gains with respect to bidding, operational decisions and investment. We acknowledge this would be a further fundamental change and support the Authority in considering this matter further with a view to potentially including this on the future work plan. We note that another alternative may be to move to a 5-minute PRS-type forecast schedule, to improve the granularity of forecast prices.
ENA, IEGA, NZ Steel, Powerco, Vector, WPI	[No response to this question]

Q3. Do you agree with disestablishing the pricing manager and allocating residual functions to other parties? If not, please explain your reasoning.	
Contact Energy	Yes
EnerNOC	Yes
Flick Energy	Yes. Flick agree with the proposal to disestablish the pricing manager role. Flick also agree with the allocation of the residual functions: The calculation of interim prices – should be automated with clearing manager overseeing. The changing of interim to final prices should also be automated (unless pricing error or UTS is claimed) – and that the clearing manager should undertake this function. Flick submit that to the extent possible automation should occur and agree that addressing pricing errors (not just material errors) should be retained with the system operator overseeing this process.
Genesis Energy	Yes
Mercury Energy	Yes, as long as the residual functions remain in place.
Meridian Energy	Yes
MEUG	MEUG has no concerns with making this change.
NZX	No comment.
Orion	Yes
Pacific Aluminium	Yes

Q3. Do you agree with disestablishing the pricing manager and allocating residual functions to other parties? If not, please explain your reasoning.	
Transpower	Yes. The removal of the ex-post pricing process could mean the residual functions are too costly for dedicated resource. We agree the clearing manager could manage the revised interim prices process. To ensure no loss of market information that supports competition and risk management, we support all existing data-sets that were produced by the pricing manager to continue to be produced.
Trustpower	Yes, we support the role of the pricing manager being disestablished and any residual functions being allocated to other parties. There will no longer be any need to undertake ex-post calculations of spot prices and the remaining roles (calculating interim prices, changing the status of prices from interim to final, and addressing material pricing errors) can largely be automated processes undertaken by the clearing manager and/or system operator. This will ensure unnecessary costs are not incurred by the market associated with funding a pricing manager to continue to undertake a significantly reduced role.
ENA, IEGA, NZ Steel, Powerco, Vector, WPI	[No response to this question]

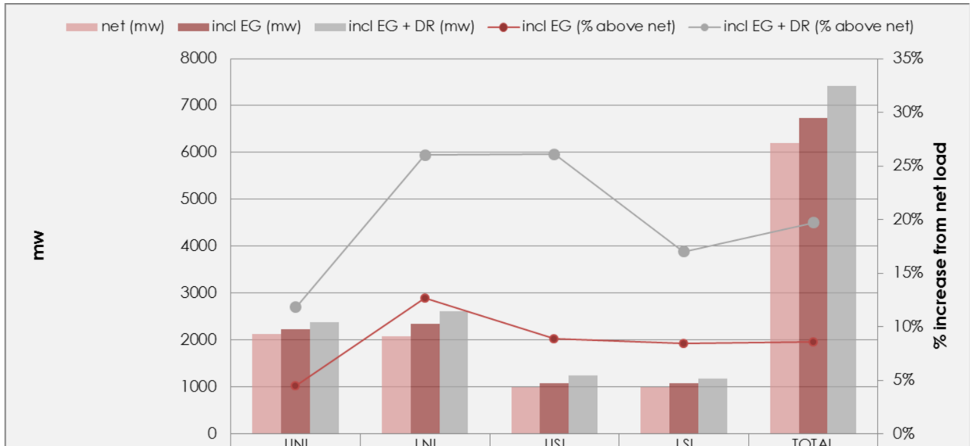
Q4. Do you agree with the general approach of using default scarcity values to handle generation shortages? If not, please explain your reasoning.	
Contact Energy	Yes, this is a more efficient approach than using an infeasible price as an indicator of a generation shortfall these never flow through to final prices. This gives a sufficient indicator to demand and would create improved price certainty in the forecast schedules subject to all demand capable of being shed being bid in as stated above. However, we question is whether the proposed scarcity values are high enough as to not act as a cap. This value of \$10,000/MWh is less than the VOLL value of \$20,000/MWh as stated in Part 12 of the Code, a value which has not been adjusted for inflation.
Contact Energy	***2. Artificially capping the market will not lead to the best outcomes*** *We do not believe that artificially capping the market at \$10,000/MWh will lead to the best market outcomes. We note that the Authority considered two alternative approaches to derive the assessed economic cost of curtailment to consumers. This approach indicated a range of values (around \$10,000/MWh to \$60,000/MWh for New Zealand), recognising that costs were expected to vary according to each situation and deemed a scarcity price of \$10,0000/MWh reasonable.* *The proposed cap value of \$10,000/MWh appears to be less than the break-even price for fast start options (e.g. batteries and peakers) with low capacity factors. Undercutting the break-even price will discourage investment in market based solutions and potentially make the capacity situation worse.* *As proposed, we do not think the proposed scarcity values are high enough. To put this into context, the value of \$10,000/MWh is less than the VOLL value of \$20,000/MWh as stated in Part 12 of the Code and this value has not been adjusted for inflation. In the event the Authority does proceed down this path we believe at a minimum there needs to be a process in place to review the \$10,000 cap at regular intervals*
EnerNOC	Yes. EnerNOC recommends that the following points be taken into account when defining the relationship between default energy scarcity values and contingency event instantaneous reserves constraint violation penalty (CE IR CPV) values: 1) IR deficits to occur before load shedding 2) IR deficits should not occur if there is offered generation available, even if this generation is offered above energy scarcity values 3) CE IR CPV value should not be marginally below default energy scarcity values, as this would imply that at times of energy capacity shortage the value of IR is less than the value of energy capacity when in fact they are equal due to the fact that an extra 1MW of IR will make and extra 1MW of energy capacity available

Q4. Do you agree with the general approach of using default scarcity values to handle generation shortages? If not, please explain your reasoning.	
Flick Energy	Flick notes that the Authority is proposing to assign default scarcity pricing values to all forecast demand not bid by purchasers. Currently generation shortage leads to emergency load shedding. Triggering scarcity pricing provisions – if the system operator instructs widespread load shedding spot prices are scaled generation weighted $10k – 20k / MWh in each Island. The current set up gives revenue certainty for last resort generation or demand response – and provides incentives to hedge. However, the current arrangement provides uncertainty in real time about whether scarcity pricing will be triggered. Flick agree with the Authority that is undesirable. Flick also agree that in these situations participants should have actionable price signals to maximise generation or demand response. **The Authority is proposing:** assigning default scarcity values to all forecast demand not bid by a purchaser. Emergency load shedding of demand assigned scarcity values would show in forecast schedules (the price responsive schedule PRS and the non-price responsive (NPRS)) Then if not resolved with rebids and reoffers in dispatch prices in real time. Proposed three scarcity blocks for forecast demand: 5% at $10k, 15% at $15K, and 80% at $20k These three blocks would be assigned to load not bid by purchasers. Flick Agree that applying default scarcity values in this way is the best translation of the current ex-post scarcity pricing arrangements. Under this arrangement parties would be certain of dispatch prices in real-time (assuming no pricing error or UTS). Under RTP default scarcity values could be triggered for localised shortages rather than for a whole Island. Flick submit that it is positive that under RTP forecast, real-time and spot prices would be consistent for a given set of system conditions. Allowing actionable real-time prices, enabling better informed decisions.
Genesis Energy	Yes, subject to the following comments: Genesis has some concerns about arbitrarily setting default scarcity price blocks for forecast demand and embedding these within the Code. This does not provide any scope or agreed parameters for price adjustment over time. We suggest that the scarcity values should sit outside the Code where they can be transparently amended and (or) there be provisions/triggers provided for periodic adjustment e.g. not unlike how Transpower inflates the value of lost load when assessing the benefit of reducing unplanned losses of supply in grid upgrade proposals.
IEGA	Yes, we agree with the use of default scarcity prices to handle generation shortages. However, it is unclear what the default scarcity volumes might be. The proposal suggests all non-dispatched demand be allocated a scarcity price. We query whether this includes all network controlled demand, Transpower's Demand Response programme

Q4. Do you agree with the general approach of using default scarcity values to handle generation shortages? If not, please explain your reasoning.

volumes and all DG?

We refer again to Transpower's analysis[7]. The following extract shows peak price responses from Embedded Generation (EG) and Demand Response (DR) are reasonably consistent across each transmission region. This, therefore, reasonably represents the average price response from the demand side.



	UNI	LNI	USI	LSI	TOTAL
net (mw)	2132	2076	990	1002	6200
incl EG (mw)	2228	2338	1078	1086	6730
incl EG + DR (mw)	2384	2616	1248	1172	7420
incl EG (% above net)	4%	13%	9%	8%	9%
incl EG + DR (% above net)	12%	26%	26%	17%	20%

Source: Transpower TPM Submission – July 2016 – Appendix G

How is network controlled DR going to be defined in the bid stack?

We also note that Transpower is developing an ICP based demand response platform. It is reasonable to expect that demand side responses managed by Transpower will increase over time.

Is all of this capacity, being for the most part not dispatched, going to be bid at scarcity prices?

As discussed above, our view is that the EG/DG component of this capacity, if not dispatched, should then be allocated on the

[7] Transpower's TPM Submission July 2016, Appendix G by Scientia Consulting at http://www.ea.govt.nz/dmsdocument/21133

Q4. Do you agree with the general approach of using default scarcity values to handle generation shortages? If not, please explain your reasoning.	
	supply side, at the same scarcity prices. This would result in approximately 8 to 10% of supply and demand being allocated scarcity prices on each side of the market. Has this outcome been contemplated in preparing this proposal? If this outcome was considered what were the arguments for and against in developing the proposal?
IEGA	***Summary of our main points:*** *…* *5. The nodal price signals need to be considered for short run RTP efficiencies and long run new generation investments. Adding artificial price caps for network load shedding to nodal pricing is inconsistent with the Authority's views in the DGPP decision that nodal pricing should be relied on to signal peak demand and capacity constraints.*
Mercury Energy	Yes we support clarifying and streamlining the scarcity pricing regime but there needs to be a transparent process to set the thresholds and these need to be reviewed periodically. It would be inappropriate to set and forget the thresholds as the market will evolve over time. Mercury would like to see a technical working group established to set the thresholds and review them annually.
Mercury Energy	*At present, wholesale spot prices published in real-time are only indicative. The pricing manager publishes final prices for any given day at least two days after real-time. While these indicative prices are normally a sound guide to final prices, large differences can arise especially when the system is under stress making the spot prices uncertain which makes it harder for parties to make efficient real-time decisions about their consumption and generation. We are particularly supportive of scarcity pricing measures being built in to the RTP regime to replace the current scarcity pricing arrangements which are complex and confusing.* *…we believe that the proposed scarcity pricing blocks of $10,000, $15,000 and $20,000 for non-bid load, need to be carefully thought through and road tested to ensure they are set at the appropriate level because while they are not price caps they will set some de facto expectations and precedents. Mercury would like these prices to be reviewed periodically by a technical working group rather than being set and then forgotten by the Authority. This would enable them to be subject to regular, comprehensive scrutiny and adjusted if market conditions change.*
Meridian Energy	Yes

Q4. Do you agree with the general approach of using default scarcity values to handle generation shortages? If not, please explain your reasoning.	
MEUG	The general approach is agreed. The proposed scarcity price blocks in table 1 (p19) seem reasonable today. We don't have confidence that will be reasonable in 4 years-time when RTP goes live. The reason why scarcity values today may be obsolete in the near-term is rapid growth in deployment of batteries. Transpower expect:[8] • "Some specific commercial or industrial end-consumer battery applications are economic now. The case for these would be further strengthened if Time-of-Use lines charging, combined with full open access to all market energy services, were available. • Distribution-connected or community-scale batteries are expected to be economic from 2020. • Grid-connected batteries are not presently economic and we consider these are unlikely to be so before 2022." Discovery of efficient spot prices when batteries are more widely deployed, including in periods when the market is stressed may lead to quite different values and band widths for appropriate default scarcity price steps. MEUG suggest the Code require a review and update of the default scarcity values: • Just ahead of RTP going live; and • Within 3-years of RTP commencing. Codifying the latter overcomes the risk that other work the EA has in the future or lobbying from parties comfortable with the initial set of scarcity values may crowd out resources being used or delay a review.
NZX	No comment.
Orion	No. These are not necessarily generation shortages, but situations where, even with all available offered and bid resources dispatched and including transmission resources, forecast demand cannot be met.

[8] Transpower, Battery storage in New Zealand, Discussion Document, published 7 September 2017, selected summary points from p2, refer URL https://www.transpower.co.nz/sites/default/files/publications/resources/Battery%20Storage%20in%20New%20Zealand.pdf at https://www.transpower.co.nz/about-us/transmission-tomorrow/battery-storage-new-zealand

Q4. Do you agree with the general approach of using default scarcity values to handle generation shortages? If not, please explain your reasoning.	
	If such an approach is to be used the table of default values should at least reflect the actual resources available to the system, many of which are usually available at much lower cost than the values proposed in the paper. We do not believe the paper gives adequate attention to the potential impact pre-defined, and high, scarcity prices could have on generator offer behaviour in situations where generators are pivotal. In some scenarios a generator may be able to reduce quantities offered at relatively low prices knowing that the total quantity offered is insufficient and that therefore they will receive a price much higher than their offer price. At the very least this suggest the safe harbour provisions in the Code should be reviewed as part of this project.
Orion	• *We question whether a "scarcity" price, at the levels proposed, is appropriate in all or even most circumstances.* ***The price in scarcity situations*** 21. *As we understand the proposal, where there are insufficient offered or bid resources (including transmission resources) available to the SO to meet forecast demand, then administratively set "scarcity" prices should apply. The price is effectively taken from a look-up table based on the proportion of forecast demand that cannot be met. The table in the paper has three steps with prices varying between a floor at $10,000 per MWh and a cap of $20,000 per MWh. We presume that the administrative high price is communicated to the world at the same time as the SO calls on distributors to curtail demand?* 22. *The 2011 work that is said to support the proposed prices links the floor price to the need to encourage, or not discourage, investors in last resort plant.*[9] *Given the passage of time it seems reasonable to ask whether that investment has occurred? The paper provides no information.* 23. *We also note that $10,000 per MWh is a very big number, and one that will likely be a good deal higher than the next highest-priced resource available. We are not sure that the normal concepts of supply and demand curves, and the way equilibrium might be found from their interaction, are robust to such large steps. The paper mentions that more certain prices might encourage investment in batteries, and that is probably true, but if and when there is a lot of battery storage on the system, the way the batteries' control system reacts to prices that are potentially changing between very high and very low in real time, needs to be considered.* 24. *More generally though, and referring back to the point about pragmatic dispatch, we can safely say that there are usually material resources available that would reduce demand at prices (or costs) much lower than those in the table. It might be argued that these should be reflected in demand bids, but there are costs involved in coordinating all of that, particularly*

[9] Electricity Authority, Scarcity pricing – Overview, 27 October 2011.

Q4. Do you agree with the general approach of using default scarcity values to handle generation shortages? If not, please explain your reasoning.	
	for rare occurrences. On the Orion network there is typically around 50MW of storage heating load that is, for reasonably extended periods of time, available at near zero cost.[10] *If prices are supposed to reflect dispatch, and dispatch can be pragmatic, then why can't price setting be pragmatic?* 25. *This isn't just theoretical. In the examples given in the spreadsheet (published along with the consultation paper) that relate to branch constraints on Islington circuits on 25 November 2015 and 16 February 2017, in both cases these seem to have been managed by Orion responding with a modest amount of storage heating being turned off for a short period. We can be reasonably sure that this response was at near zero cost.*[11] *The proposal risks replacing a simple solution that works well with a more complex solution that works less well.* 26. *Beyond storage heating there is further relatively low cost (compared to $10,000 per MWh) response available. For example we have commercial arrangements in place with around 9MW of diesel generation that is prepared to run for $500 per MWh. There is a further 40MW of diesel generation connected to the network that, in principle, could be procured to run at much less than $10,000 per MWh.* 27. *Of course "scarcity" times might coincide with times when these sorts of resources are heavily occupied fulfilling their primary function of supporting our load management, but it will always pay to find out first.* 28. *To us this suggests that, if a look-up table approach is to be used in scarcity situations, it should include tranches of the much lower cost resource that is both available and that will in many cases actually be the resource called upon. This would align much better with the concept that prices should reflect dispatch.* 29. *More philosophically, if we are at the point of curtailing demand then, at least to some extent, the supply side of the industry – generators, the SO, the grid owner, distributors, third party aggregators and retailers – has collectively failed to meet consumers' reasonable expectations. Before we turn supply off to some of those consumers, and charge a hefty price for the demand of those that are not turned off, we need to be able to look them in the eye and say we had explored all other available options and had no choice. In our view the proposal as it stands does not do that.* 30. *To develop an analogy used at the Wellington workshop, the proposal is as if you decide to go to a restaurant based on the menu on the website, but find once you get there that the menu keeps changing even while you are deciding what to order, and then, having finally ordered the fish for the main, being told that only an entrée-sized portion is available and that you'll have to pay at the price the restaurant thinks you would have been prepared to pay for it had you not eaten for a*

[10] This amount is generally available during the day. A similar additional amount could be available at various times during the night when the significant quantity of night rate storage heating is on.

[11] Other low cost response that could be called upon for local constraint issues is switching of load between GXPs. We note in passing that purchasers do not know in real time what GXP their customers are fed from.

Q4. Do you agree with the general approach of using default scarcity values to handle generation shortages? If not, please explain your reasoning.	
	week. 31. *Interestingly, and if we understood the discussion at the Wellington workshop correctly, this approach would not apply in sustained shortage situations such as those arising in dry years when rolling outages are occurring. It is unclear to us why the proposed approach to what are now infeasibilities, if it is a good one, should not also apply in such situations. In fact aren't these the most important situations? It also raises the question of what prices are to apply in sustained shortage situations when there are rolling outages. We would judge that an understanding of that is critical to parties thinking about investment in last resort generation or equivalent approaches.*
Pacific Aluminium	Yes. Use of staged price bands appears reasonable.
Transpower	We agree that assigning a default value to all load is necessary to enable the SPD (scheduling, pricing, dispatch) model to solve in real-time. We have not considered the appropriateness of the scarcity values and load proportions. When dispatch pricing is in operation, the values may need to be reviewed.
Trustpower	We are currently uncertain whether the proposed approach of using default load blocks is the best approach possible to implementing scarcity values into the new arrangements. We consider there may be merit to adopting a "proxy generator" approach during scarcity pricing, with tranches equal to the 5/15/80% load blocks. This would remove the potential confusion caused by indicating a load block will be dispatched off, with the system operator actually shedding load, but the quantum of shed load being "remembered" and inputted as real demand to the RTD solve during the relevant periods. We note that to date the Authority has not expressly considered this approach and recommend that the Authority considers whether this may be a more pragmatic solution to adopt as part of the RTP design. We also note that, from a practical point of view, it would be very difficult for the system operator to get the exact demand response required by the dispatch schedule, i.e. some load will simply not turn off when told and so there will be a natural tendency to seek a greater level of curtailment than required by the dispatch schedule.
ENA, NZ Steel, Powerco, Vector, WPI	[No response to this question]

Q5. Do you agree with using default scarcity bids before generation or dispatchable demand offered at a higher price in the dispatch schedule? If not, please explain your reasoning.	
Contact Energy	Our interpretation of the proposal is that the market will be capped by the scarcity values. The risk in setting a price cap is that necessary price signals to encourage investment in low utilisation assets will not be high enough. We believe more rigour is required in setting the price cap.
EnerNOC	Yes, however, if there are generation or dispatchable demand offers above the scarcity bid values it would be an indication that the scarcity values may need revision.
Flick Energy	Flick note that the change from the current approach is that default scarcity bids could be dispatched before generation bids or demand offers with higher prices. Agree that shedding load at scarcity pricing values on rare occasions would be preferable to scheduling other resources that have an even higher cost.
Genesis Energy	See response to Q4 above.
IEGA	In principle no, we do not agree with using scarcity bids before generation. The Authority has advised in numerous other rule changes or proposals[12] that nodal spot pricing is the most efficient mechanism for incentivising new generation investment and co-optimisation of generation and transmission investments. For example, the prior ACOT capacity pricing regime was put in regulations in 2007 to ensure that DG would likely dispatch at the most efficient time – that is, during periods of peak demand. The Authority has removed this mechanism as being inefficient and a subsidy. That is, the Authority is seeking to have a 100% reliance on spot nodal price signals for new investments. The use of default scarcity pricing load bids ahead of generation (for ~20% of the load) effectively removes or dampens the nodal price signals for new local generation investments, for battery storage and for market priced demand response. The Authority must now allow the nodal price to be freely determined by the market without constraints. Artificial price caps for different classes of dispatch will result in the nodal investment signals are lost. As noted for Q1 above, our view is that DG bids and volumes must be allocated to the supply side to ensure adequate price discovery and a level playing field between all generation market participants. Dispatching scarcity ahead of generation bids applies a notional price cap in the spot market for all DG price takers behind the GXP.

[12] For example, the December 2016 decision to change Part 6.4 of the Code; TPM Second Issues Paper

Q5. Do you agree with using default scarcity bids before generation or dispatchable demand offered at a higher price in the dispatch schedule? If not, please explain your reasoning.	
Mercury Energy	Yes
Meridian Energy	Yes
MEUG	Agreed
NZX	No comment.
Orion	Partially, and subject to our response to question 4. We note however that, if it actually happens, demand curtailment is a very blunt instrument which results in total loss of supply to a group of consumers who will not necessarily experience impacts in line with the very averaged concept that is VoLL. It is conceivable that dispatch of higher cost offers or bids may have been better in hindsight.
Pacific Aluminium	Yes
Transpower	We defer to the responses of participants directly affected by the design choice.
Trustpower	Yes, subject to our points under Q4, we agree with the use of default scarcity bids provided that they remain a reasonable reflection of the value of lost load (**VoLL**). We note that these values have not been updated for a number of years and may no longer reflect the utility to consumers of electricity supply. To the extent that these values may be out of date then a "pseudo" cap will have been introduced into the market that may not appropriately reflect the real demand curve. We consider that to mitigate this risk the Authority should undertake a review of the VoLL values prior to the commencement of the proposed changes. At a minimum a CPI adjustment to the values each year should be considered[13]. Going forward, we consider that it would be valuable to introduce a requirement for a more frequent review of the VoLL, for

[13] This has been the approach adopted in the NEM since 2012.

Q5. Do you agree with using default scarcity bids before generation or dispatchable demand offered at a higher price in the dispatch schedule? If not, please explain your reasoning.	
	example a required annual or biannual review. Likewise, where an event occurs which triggers VoLL setting the price in the market then a specific review of the event should be undertaken. There may also be value in introducing more granularity around the proposed tranches of load in the future. This should be explored as part of a post-implementation review of the RTP arrangements.
ENA, NZ Steel, Powerco, Vector, WPI	[No response to this question]

Q6. Do you agree the system operator does not need to make changes to the existing process it uses to notify distributors of emergency load shedding?	
Contact Energy	Yes, but we are concerned that based on the proposed Grid Emergency (GE) Code changes that we will see more GEs declared and an increase in forced load shedding rather than the market delivering a solution. This can be avoided if the scarcity price levels are high enough that they are above market offers/bids and that all demand capable of being shed is able to be bid into the market.
EnerNOC	Yes
Flick Energy	Flick note that at present no load at conforming nodes participates in the dispatchable demand scheme. Instead the SO issues instructions to curtail load. And that in practice the SO manages pragmatically (rather than to a strict schedule). Authority proposes scarcity prices should apply if they occur in the in the dispatch schedule even if no load shedding occurs in practice. Flick agrees with this proposed approach.
Genesis Energy	Yes. Genesis notes that it does not consider changes to be necessary, at this time, rather, we believe this is part of a separate workstream and contingent on phase three of the Electronic Dispatch Facility (**EDF**) programme.
IEGA	In our view, the assumptions underpinning the proposed dispatch process rely on historic practices. Both DG and DR have historically been dispatched in response to strong RCPD and ACOT price signals. With the loss of ACOT payments, DG and DR will be incentivised to aggregate and dispatch into the most favourable market/s. We therefore believe there will be a co-dependency between whether DG can be bid on the supply side of the spot market, as we propose above, or otherwise end up captured by the processes for dispatch of emergency load shedding. For example, if all DG is: • allocated scarcity prices and is on the supply side of the spot market, then how is this capacity dispatched to ensure no emergency load shedding? • aggregated with DR on the demand side of the spot market, and DG cannot receive constrained-on payments as it is non-conforming, this capacity has no mechanism to be dispatched ahead of emergency load shedding. We suggest the market price should be set by generator offers before any emergency load shedding is undertaken. We would like the Authority to first address the matters discussed in relation to Q1 to Q5 before making decisions on the emergency load shedding procedures.

Q6. Do you agree the system operator does not need to make changes to the existing process it uses to notify distributors of emergency load shedding?	
Mercury Energy	Mercury believes the system operator load shedding process going forward needs to be a well-documented, transparent, efficient process that is applied consistently, is made as public as possible in a timely manner and takes advantage of latest advances in technology. We believe that there are more efficient means of communicating with potential load shedders than resorting to phone calls. This is particularly important as load shedding is not an exact fit with bids. We suggest that the load shedding process be reviewed in the upgrade of the electronic dispatch function.
Meridian Energy	Yes
MEUG	Agreed
NZX	No comment.
Orion	Yes, at least at this stage. We are not sure emergency load shedding is the right term. We suspect many and perhaps most situations will be able to be handled with much lower impact actions by distributors. In fact, and as noted at the Wellington workshop, this typically happens now. We think it is more important that the SO does not make changes to the pragmatic approach to real time dispatch.
Pacific Aluminium	Yes
Powerco	*The existing process used to notify distributors of emergency load shedding is acceptable.*
Transpower	Yes. We agree the introduction of RTP would not require a change to the existing processes.
Trustpower	Yes, we consider that the arrangements will continue to work appropriately. However we note that greater transparency of notifications of events would be valuable so the wider market is aware of any real time action being undertaken.

Q6. Do you agree the system operator does not need to make changes to the existing process it uses to notify distributors of emergency load shedding?	
Vector	*We believe it is pivotal that the System Operator and electricity distribution businesses (EDBs) retain a degree of discretion in how they instruct and implement emergency load shedding rather than the regulations being too descriptive and process driven. This is to ensure they both have adequate flexibility to make the best decision given the circumstances which can vary widely.*
ENA, NZ Steel, WPI	[No response to this question]

Q7. What is your view on the preferred treatment of disconnected nodes? Please explain your reasoning	
Contact Energy	We agree. We also propose that there needs to be more rigour applied to the timing and accuracy of planned outage information to ensure the accuracy of Real Time Pricing (RTP).
EnerNOC	Disconnected nodes should have their price determined by using the next most suitable node.
Flick Energy	Flick agrees with the suggested approach of having proxy prices assigned at nodes that are marked as disconnected. With the proxy based on an adjacent node. Flick supports this approach as we think this is an efficient way to avoid inappropriate scarcity values at disconnected nodes.
Genesis Energy	Genesis considers the proposed treatment of disconnected nodes is reasonable. We recognise there must be a trade-off between achieving optimal accuracy and the administrative costs of removing all approximation.
Mercury Energy	Mercury supports the treatment specified in the consultation paper for the reasons outlined there. We support the system operator assigning a proxy price to nodes marked as dead or disconnected by the market system. This proxy would set the price at an appropriate adjacent node for the relevant trading period multiplied by the historic average of the affected node's location factor over some period.
Meridian Energy	Meridian supports the Authority's proposal to set a proxy price for disconnected nodes where the proxy price would be set based on the price at an appropriate adjacent node for the relevant trading period multiplied by the historic average of the affected node's location factor. The location factor adjustment should be based on a period of similar grid configuration.
MEUG	No view.
NZX	No comment.
Orion	No comment.
Pacific Aluminium	The Authority's proposed approach to adopt a proxy price is reasonable.

Q7. What is your view on the preferred treatment of disconnected nodes? Please explain your reasoning	
Transpower	We are comfortable with the proposal by the system operator to use a proxy price, although we defer to the responses of participants directly affected by the design choice. A further idea is to investigate the viability of building the grid model for the dispatch schedule from the SCADA indications for grid assets. As with the proposal for proxy price, existing grid owner offer policy would not change. We consider there is a wider market design question of whether **for dispatch**, prices at all the market nodes are needed. As we submitted previously[14], "there may be value in considering other market design issues that drive price risk for purchasers; for example, whether it is necessary for all nodes on the grid to be pricing nodes."
Trustpower	We support the Authority's proposed treatment of disconnected nodes.
ENA, IEGA, NZ Steel, Powerco, Vector, WPI	[No response to this question]

[14] Transpower submission *Aligning forecast and final prices* 23 August 2013, to Wholesale advisory group.

Q8. Do you agree that it is not desirable to apply a cumulative price limit under RTP? If not, please explain your reasoning	
Contact Energy	Yes. However we are interested in how the System Operator gets participants to curtail demand.
EnerNOC	A cumulative price limit should not be imposed as this will result in distorted price signals being sent to the market (e.g. generation or dispatchable demand capacity my not be invested to cover dry year risk).
Flick Energy	Flick agrees that it is not desirable to apply a cumulative price limit under RTP and note that the rolling outage provisions in the Code would apply if there was an ongoing need to curtail demand.
Genesis Energy	Yes
Mercury Energy	Yes
Meridian Energy	Yes
MEUG	Agree with paragraph 3.46 “Overall, we think it is preferable to not incorporate a cumulative limit in RTP, but instead to rely on existing provisions in the Code relating to rolling outages”.
NZX	No comment.
Orion	We believe the rationale for the cumulative price limit was to ameliorate cumulative financial effects during sustained high priced periods. We do not see why this rationale is no longer relevant just because the way final prices are produced is different?
Pacific Aluminium	Yes – agree that existing Code provisions relating to rolling outrages[sic] should continue to be appropriate.
Transpower	Unsure. While we agree with the design objective that prices must be formed in real-time to be actionable, we consider the design would not be working properly if the remedy relies on recourse to rolling outages. The removal of the cumulative price limit

Q8. Do you agree that it is not desirable to apply a cumulative price limit under RTP? If not, please explain your reasoning	
	could increase pressure on the system operator to deploy rolling outages when capacity is constrained, rather than using existing grid emergency process. An alternative option could be to apply scarcity pricing for both capacity (grid emergencies) and energy (security of supply) shortfalls. A generic cumulative price limit could mitigate participant exposure to sustained periods of scarcity prices and reduce the complexity of investment decisions.
Trustpower	No, we consider that there is potentially value in maintaining a cumulative price limit to apply during scarcity events as a mechanism for reducing price risk during tight market situations. This would help to mitigate risk to retailers and would be consistent with the fact that VoLL would be anticipated to decline during a scarcity event, reflecting impacted customers moving to alternative arrangements where possible. For example, a household switching to gas for cooking during the event; or a business bringing in a diesel generator to supply power. We note that maintaining a cumulative price threshold would align with the fact that the proposed scarcity prices are an administered solution in any case. Further, scarcity values would be unlikely to be reached that frequently (though any notional “real-time” prices published by the Authority during the transition period would test this view) and as a result there should not be a significant distortion to investment signals, through a reduced ability to recover costs. We consider there would be value in the post implementation review considering the level set for the cumulative price limit to determine if it remains appropriate. We also consider that following an event which results in the cumulative price limit being applied there should be a thorough review undertaken by the Authority, including the circumstances leading up to the cumulative price limit being triggered and the pricing implications.
ENA, IEGA,NZ Steel, Powerco, Vector, WPI	[No response to this question]

Q9. Do you agree the current principle of partially relaxing reserve procurement before invoking emergency load shedding should continue under RTP? If not, please explain your reasoning	
Contact Energy	Yes and no. We do not believe the reserve requirement should be relaxed. We are however comfortable with a scarcity price for reserve to be modelled below the scarcity energy value. The practical impact is that the grid will operate in a less secure state before load shedding would occur. As per our response above, we do not believe the $9.5k is a high enough value to represent scarcity.
EnerNOC	Yes This can be quantified by the following back of the envelope calculation: $VOLL_{load\ shedding}$ = $5,000/MWh $VOLL_{AUFLS}$ = $15,000/MWh $Q_{load\ shedding}$ = 10MW (assumed that average load shedding will be 10MW for a 30 minute period) Q_{AUFLS} = 870MW (assumed 14% of average peak demand of 6200MW) P(UFE) = 0.00017 (3 UFE per year, duration 30 minutes) Cost of load shedding: $Cost_{load\ shedding} = VOLL_{load\ shedding} \times Q_{load\ shedding}$ $Cost_{load\ shedding}$ = $5,000/MWh x 20MW / 2 $Cost_{load\ shedding}$ = $25,000 Cost of reducing reserve procurement: $Cost_{reserve\ requirement\ reduction} = VOLL_{AUFLS} \times Q_{AUFLS} \times P(UFE)$ $Cost_{reserve\ requirement\ reduction}$ = $15,000 $Cost_{reserve\ requirement\ reduction}$ = $1,109
Flick Energy	Existing pricing process applies an adjustment if automatic under-frequency load shedding AUFLS occurs. Prices caused by a shortage of reserves are limited to greater of – three times highest scheduled energy offer price or highest priced offer that cannot be supplied (FIR or SIR). This adjustment after the fact is incompatible with real time prices. Flick submits that it is important that in these uncommon situations that participants have access to actionable real-time prices,

Q9. Do you agree the current principle of partially relaxing reserve procurement before invoking emergency load shedding should continue under RTP? If not, please explain your reasoning	
	enabling improved decisions.
Genesis Energy	Yes
Mercury Energy	While we accept that the current process of relaxing reserve procurement before invoking emergency load shedding makes sense, we strongly urge caution around the price applied when reserves are relaxed. Scarcity prices for reserves need to be carefully considered, potentially via a technical working group. It is undesirable that reserves are valued below energy, and relaxing the reserve requirement will lead to the reserve prices appearing artificially lower than they would otherwise, sending incorrect pricing signals to the market about reserve needs. This is undesirable and more reserve being offered into the market should be encouraged.
Meridian Energy	Yes
MEUG	Agreed
NZX	No comment.
Orion	Yes More generally we believe the approach of relaxing constraints can have wider application. For example a reduction in modelled security level might reduce the need for load shedding, and we are reasonably sure that if you asked the customers that are shed if they would have preferred just running the risk of being shed, the answer would have been "Yes!".
Pacific Aluminium	Yes
Transpower	Yes, we agree with the principle of partially relaxing reserve procurement before invoking emergency load shedding. The inability to maintain normal reserve cover should trigger a Constraint Violation Price (CVP) in the dispatch schedule.

Q9. Do you agree the current principle of partially relaxing reserve procurement before invoking emergency load shedding should continue under RTP? If not, please explain your reasoning	
	We anticipate that the CVP will reflect the expected cost of an AUFLS event caused by a shortfall in reserves, and that it will be lower than the lowest scarcity pricing value. This CVP may need review as we develop RTP, and equally could evolve over time once RTP is operating.
Trustpower	Yes, we support maintaining the principle of partially relaxing reserve procurement before invoking emergency load shedding.
ENA, IEGA, NZ Steel, Powerco, Vewctor, WPI	[No response to this question]

Q10. Do you agree with the proposed removal of the high spring washer pricing provisions in the Code? If not, please explain your reasoning	
Contact Energy	Yes, subject to more assessment of past events to determine the impact of applying scarcity pricing e.g. are we likely to see an increase in GEs for high spring washer situations (HSWS) as a result of the proposed code changes? How will the current negative prices that evolve from a HSWS be treated?
EnerNOC	Yes
Flick Energy	Yes. Flick notes that the Authority does not expect that the outcomes under RTP would be significantly different than currently (because very few resources currently priced above $10k). Flick notes that introducing default scarcity values for forecast load will in effect limit prices in a HSWPS. Introducing RTP should facilitate greater voluntary demand bids and other actions in response to HSWPS to reduce their impact. Flick agrees with the Authority's proposal to remove HSWPS provisions from the Code.
Genesis Energy	Yes
Mercury Energy	We understand that high spring washer (HSW) prices are likely to be "relaxed" under RTP by scarcity pricing values and increased responsiveness by both supply and demand. Where the HSW price is below the lowest scarcity price it is more likely that the HSW price becomes final and erroneously so. This is because these prices will not so much reflect economic costs (i.e., marginal generation) but potentially many multiples thereof due to sensitivities in SPD. In this way, many HSW prices may go unadjusted in RTP. We would like the EA and the system operator to do further work on alternative options aimed at reducing this impact. Mercury has two suggestions that we think are worth further analysis, the first is to look at the model formulation changes mooted in the Authority's consultation on HSWs in June 2012. The second could be to use the highest priced generation as a proxy for a HSW outcome instead of a relaxation and potentially even include defaults such as 0 in the unconstrained area and last offered generation in the constrained area.
Meridian Energy	Possibly. Meridian would first like to see the anticipated pricing outcomes and compare them with pricing outcomes under the current relaxation rules. We submit that the Authority should carry out analysis as recommended in out covering letter before making a decision. Currently we are not confident that demand response will necessarily relax high spring washer pricing situations and would not want to see overall price increases for consumers in these situations as a result of real-time pricing.
Meridian Energy	***High spring washer pricing situations (HSWPS)*** *Meridian agrees that, ideally, demand response would automatically correct or relax any potential HSWPS. However, in the*

Q10. Do you agree with the proposed removal of the high spring washer pricing provisions in the Code? If not, please explain your reasoning	
	absence of this correction, the proposed scarcity pricing bands would set prices in a HSWPS. In order to understand the significant of this change, Meridian would like to be able to compare the potential pricing outcomes in HSWPS under both the existing relaxation factor and what might happen under real-time pricing using the scarcity pricing bands. We recommend that the Authority undertake analysis over a period of several years to determine what the pricing outcomes would have been under the proposal during HSWPS. Such analysis should be undertaken in advance and inform the Authority's final decision. We have some concern that the new process could drive higher prices to the detriment of consumers. *We understand that any such comparison might be artificial if the Authority's expectation is that demand response will provide the relaxation of a HSWPS. Meridian does not, however, share the Authority's confidence on this point. Further, even if the Authority's expectation is borne out, the comparison would be useful as a worst case scenario.*
MEUG	Agreed.[15]
NZX	No comment.
Orion	No comment.
Pacific Aluminium	Yes
Transpower	Yes. The removal is a necessary consequence of moving to dispatch pricing.
Trustpower	Yes, in principle we support this approach as it is consistent with ex-ante pricing being established. We note that the Authority is proposing to remove the current protection that enables spring washers to be relaxed on occasions where the constraints are only just binding. We appreciate that under the proposed RTP arrangements high spring washer events would trigger default scarcity prices (most likely $10,000/MWh) , which are much lower than the potentially high spot prices that could be triggered currently of $100,000/ MWh or more. However we consider that the removal of the current spring washer relaxation capability, may result in an increase in the frequency of spring washer events impacting on prices. As outlined in our response in Q1, we consider that there may be a case for applying a high spring washer price ratio limit (ex-

[15] The Q&A on High spring washer pricing situations published 13 September was a useful supplement to the consultation paper on this topic.

Q10. Do you agree with the proposed removal of the high spring washer pricing provisions in the Code? If not, please explain your reasoning	
	ante) in the RTD schedule. This would mitigate some of the risk to retailers. We acknowledge that the current arrangements would not be fit for purpose as they would require ex-post adjustments to take place. We would be interested in the views of other participants around this particular matter, particularly as to whether there should be a maximum applied of either the lowest VoLL tranche ($10,000) or a price ratio limit.
ENA, IEGA, NZ Steel, Powerco, Vector, WPI	[No response to this question]

Q11. Do you agree with the proposed changes for demand inputs? If not, please explain your reasoning	
Contact Energy	Yes
EnerNOC	Yes, however, we would like further explanation as to the assumptions the system operator makes in regards to forecasting net demand. As market changes are continually occurring there is no assurance that DER will be operating in the manner that it currently does. New technology is allowing sophisticated control of DER that historically operated in a predictable manner. This points to the fact that under the RTP proposal there are at least two DER that cannot participate within the offer stack, these being hot water load and embedded generation. With the introduction of the dispatch-lite function on the demand side a similar mechanism for the supply side of the market should also be developed. With the inability of some DER to indicate their operation intentions through the offer and supply stack EnerNOC is concerned with the use of net demand used in the dispatch schedules. We believe to have an equal and competitive market gross demand will be needed to give a complete view of the supply and demand stack.
EnerNOC	***2 Demand-side compliance obligations*** *Under the proposed real-time pricing regime, we have a concern that non-conforming GXPs will be disadvantaged and have onerous compliance obligations in comparison to conforming GXPs. Under the current bona fide provision in the code, it is unclear if load curtailment at a non-conforming node can be made for reasons relating to changing market conditions or other changes at the site, other than a physical reason.* *This could lead to a non-conforming GXP been forced into the dispatchable demand program if they wish to have the ability to perform any short notice demand response that would occur within gate closure.*
Flick Energy	Flick notes that the Authority and the System Operator expect that changing to bottom-up forecast of load at each node would be more accurate – and on this basis Flick is supportive. Flick is also supportive of the recommendation that demand inputs for non-dispatchable load at non-conforming nodes being based on actual load values – noting that this is expected to be more accurate – and is consistent with current process for final price calculation.
Genesis Energy	Yes
Mercury Energy	Yes

Q11. Do you agree with the proposed changes for demand inputs? If not, please explain your reasoning	
Meridian Energy	Yes
MEUG	Agreed
NZ Steel	*The real-time unit price would be derived from the forecast load and available supply. The forecast load component of this equation requires further consideration:* *a. Pricing is a combination of volume and unit price. The unit price determined by the SO pricing model is only part of the equation.* *b. Conforming nodes have predicted load calculated by the SO. We note however, the Authority work has shown conforming load to have the largest variation to actual[16] . Until the project of work to address this issue is completed, it will impact on the RTP regime proposed.* *c. Non-conforming GXPs are required to nominate load and price on a half-hourly basis before gate closure ie one-hour out. The current and proposed mechanisms for altering load bids within gate closure are far from clear.* *d. The result is consumers at conforming nodes get the full benefit of RTP ie the price is know before (and during) each trading period and load can be varied at will.* *e. For non-conforming GXPs we suggest what is being proposed is not RTP. The unit price will be known, but consumers at these GXPs need to meet certain (unclear) criteria before the load nominated an hour before the unit price is determined, can be varied.* *f. Given a. & b. above, RTP as proposed disadvantages consumers at non-conforming GXPs and there are no immediate plans to address the issue of conforming loads impacting the supply/demand equation, nor to further reduce Gate Closure.*
NZX	Yes. Load forecasts - referred to as “the expected profile of demand” in the Code - is an important input to the dispatch schedule and hence final prices.

[16] Electricity Authority, “Making hours-ahead price forecasts more accurate”, Consultation paper, 9 February 2016.

Q11. Do you agree with the proposed changes for demand inputs? If not, please explain your reasoning	
	To ensure transparency we think it is important that the methodology behind calculating dispatch schedule forecast demand is published in a similar manner to the PRS and NRS schedules. Therefore we suggest that Clause 13.7A is expanded to cover dispatch schedule load forecasts.
Orion	Also see our response to question 12. A bottom up forecast of load does not of itself provide sufficient information, as in most cases more generation will need to be dispatched to meet any given demand due to losses. It is unclear from the paper how forecast demand gets translated to required supply. Perhaps more importantly, if there is a significant increase in demand response will this potentially make more nodes non-conforming, and what are the implications of that?
Pacific Aluminium	Yes
Transpower	Yes. We expect the specification of demand input to the dispatch schedule to be a significant work stream for the implementation phase of the project. As the owner of both the SCADA system and IONS meters which now play the key role for price formation, we consider the Code will need to provide a clear definition for the demand input and description for the process.
Trustpower	Yes, we agree with moving to a bottom-up load forecast. We also consider it is important that the forecasting approach, including details of all the components that are taken into account, should be made transparent.
WPI	*DSB&F obligations at non-conforming nodes: WPI's obligations under the DSB&F requirements at non-conforming nodes will also be an impediment to WPI acting on RTPs. We suggest that the current DSB&F rules and obligations at nonconforming nodes should be reconsidered as part of the RTP change project noting that:* *a. A large majority of WPI load changes are unplanned sudden reductions and therefore are not reflected in our DSB&F data.* *b. Actionable RTP and new technologies are likely to increase demand response and reduce the pre-trading period predictability of load at conforming nodes.*

Q11. Do you agree with the proposed changes for demand inputs? If not, please explain your reasoning	
	c. The use of real time SCADA data and new forecasting techniques could be a suitable alternative to DSB&F.
ENA, IEGA, Powerco, Vector	[No response to this question]

Q12. Do you agree that ION meter data should be the primary data source for demand inputs? If not, please explain your reasoning	
Contact Energy	Yes, subject to cost and how this is allocated.
EnerNOC	Yes, the best available data should be the primary data source followed by the next best etc.
Flick Energy	Flick has no comment on the ION metering data – except that in general terms - Flick is supportive of measures to increases accuracy across the industry.
Genesis Energy	Yes
Mercury Energy	Yes
Meridian Energy	Yes – and it should be a prerequisite rather than an option for implementing real-time pricing.
Meridian Energy	*For real time pricing in the dispatch schedule, the System Operator is proposing to take the actual system demand and then bias it according to the expected load at the end of the five minute period. The paper proposed that use of Ion Meters is an "option" – Meridian considers that this should be a prerequisite. Additionally, the methodology utilised for the five minute demand bias should be transparent and tested to measure its accuracy on an ongoing basis.*
MEUG	Agreed because the benefits of improved data quality from ION meters is likely to exceed the incremental cost to implement of between $120,000 and $180,000 (if not already implemented before RTP goes live in 4-years).
NZX	Yes. Initiatives such as this should be prioritised as it is an intermediary step to transition to RTP and can increase price certainty for participants by eliminating metering as a cause of provisional prices under the current system. Clause 13.141 requires the pricing manager to publish demand half hour metering information every day for the previous trading day. Market demand is a key driver behind wholesale prices. We suggest that the Code should be amended to allow a similar demand half hour metering data set to be published to WITS by either the grid owner or system operator.

Q12. Do you agree that ION meter data should be the primary data source for demand inputs? If not, please explain your reasoning	
Orion	If demand data is needed then the source should be the best available. It is less clear what the demand data is for. It appears it forms the basis of a short term forecast, but how this forecast is produced and how it relates to the longer term (say day ahead) forecast that underpin forecast prices is unclear. Also how will the longer term forecast adapt to actions taken in real time? The essence of the problem here is that any and all response will be reflected in changes in metered quantities. The SO is going to need to know the components of the demand it is looking at in order to manage dispatch for the next period. Suppose for example that the SO sees a demand of 5,800MW, and uses this to forecast demand of 6,000MW for the next dispatch period. Also suppose that there are only dispatchable offers and bids for 5,900MW, so the SO sets the real time price to (say) $10,000 per MWh since it expects to have to instruct EDBs to curtail load. Now suppose that price and curtailment signals reach the real world and demand turns out to be 5,800MW. What does the SO do with this number for the next dispatch period, as it now includes an unknown combination of unbid demand response and curtailment. Does the SO interpret this load as meaning curtailment is no longer required - meaning that the scarcity price no longer applies - or that the curtailment must stay in place and therefore so to must the scarcity price? The wider question here is how does the SO deal with unforecast demand response, and changes in it, that occur throughout out the day? We note that, by definition, metered demand can never in real time exceed the resources available to meet it, but metered demand may always reflect responses that are, at least to some extent, unknowable.
Pacific Aluminium	Yes – the industry should adopt new technology which delivers improved accuracy.
Transpower	Yes. The objective for price certainty under RTP requires confidence in the robustness of the forecast demand used in price formation. As the owner of both the SCADA system and IONS meters which now play the key role for price formation, we consider the Code will need to provide a clear definition for the demand input and description for the process.
Trustpower	Yes, we support using ION meter data as the primary data source.
ENA, IEGA, NZ Steel, Powerco,	[No response to this question]

Q12. Do you agree that ION meter data should be the primary data source for demand inputs? If not, please explain your reasoning	
Vector, WPI	

Q13. What is your view on the best approach to incorporate dispatchable demand within an RTP framework? Please explain your reasoning	
Contact Energy	Yes, we agree dispatchable demand should be dispatched from the dispatch schedule rather than in the non- responsive schedule (NRS). The rollout of EDF Phase III is essential to broadening participation. Web services will facilitate participation from new participants / technology. GENCO is a barrier. We agree with Authority's view on the potential for dispatchable demand participants to re-bid within trading period if yo-yo dispatch is an issue, and that this would result in no constrained on-off payments.
ENA	*Members consider that there will need to be a coordinated approach to the provision of demand response in the future as the system operator(s) will need greater scrutiny of demand response at GXP level (load shedding in the distribution networks) given the level of the default scarcity values.*
EnerNOC	EnerNOC is supportive of the Authority's efforts to introduce an effective dispatchable demand program, however, the current dispatchable demand system proposed does not compensate dispatchable demand units in an equal manner to a generation unit. Further, we have reservations on the lack of flexibility and compliance obligations that will be required as a dispatchable demand participant, these been: 1) The lead time on dispatch instructions for dispatchable demand participants will greatly reduce under the proposed real-time pricing proposal 2) Lack of flexibility, participants needs should be incorporated as follows: a. Response-time requirements b. Duration of dispatch period c. Limited resources to revises offers due to changing site and market conditions d. Dispatch-on obligations and associated compliance
EnerNOC	***3 Dispatchable demand*** *EnerNOC is supportive of the Authority's efforts to introduce an effective dispatchable demand program, however, the current dispatchable demand system proposed does not compensate dispatchable demand units in an equal manner to a generation unit.* *Further, we have reservations on the lack of flexibility and compliance obligations that will be required as a dispatchable demand*

Q13. What is your view on the best approach to incorporate dispatchable demand within an RTP framework? Please explain your reasoning	
	participant, these been: 1) *The lead time on dispatch instructions for dispatchable demand participants will greatly reduce under the proposed real-time pricing proposal* 2) *Lack of flexibility, participants needs should be incorporated as follows:* a. *Response-time requirements* b. *Duration of dispatch period* c. *Limited resources to revises offers due to changing site and market conditions* d. *Dispatch-on obligations and associated compliance* *If the energy market has a true ex-ante and cost reflective price there is little benefit for dispatchable demand participants to expose themselves to onerous compliance obligations that are imposed under the current dispatchable demand regime, this is illustrated in the following points:* 1) *By participating as a dispatchable demand unit you are signaling to the market the price that you are willing to pay and participants who hold market power can react accordingly* 2) *Downward pressure put on spot prices by dispatchable demand participants is never incurred during a time when the participant is consuming energy, as for the spot price to be reduced by a dispatchable demand unit that unit must be dispatched* *This leads to the fact that dispatchable demand units are not fairly compensated for the benefits that they deliver to the system, under the current and proposed market. As a result, the true benefits available from dispatchable demand units will not be utilised to their full potential. If the Authority's objective is to allow distributed energy resources (DER) to operate efficiently and equally in the New Zealand electricity market, where it is economic to do so, then they must be treated as an equal resource or compensated accordingly.*
Flick Energy	The proposal that dispatchable demand is despatched from the dispatch schedule in the same way generators are currently,

Q13. What is your view on the best approach to incorporate dispatchable demand within an RTP framework? Please explain your reasoning	
	seems sound. Those with close working knowledge of these processes are clearly best placed to assess the impact of these technical aspects. Again, though it would appear positive to have processes simplified and that under RTP dispatchable demand purchasers would no longer need to provide the pricing manager with next day metering data.
Genesis Energy	Genesis is of the view that the existing dispatchable demand (**DD**) product has been designed 'by industry, for industry', which puts off many potential DD participants with its complex, jargon-laden code specifications. This point was well raised at the August 22 workshop: the focus of consumers is their business, not electricity, and few have the resources available that would justify participation in current DD. Specific to the consultation paper, Genesis considers the SO's proposal to include ramp rates and minimum cycle times for DD bids would drive further complexity into what is already a complex product. As for concerns about a 'yo-yo' effect, we see this to be part of operating in the market, and note that, in reality, no DD participant would bid all of their load at one price: they would offer it in tranches, meaning a detrimental 'yo-yo' effect would be very unlikely. We also note that it is likely that DD participation – and demand response generally - will be automated in the future (e.g. battery storage can be used to provide swing) which means it is important for the RTP framework not to hinge on DD participation as it is currently designed.
Mercury Energy	Mercury agrees with the proposal outlined in the consultation paper in para 3.77 that dispatchable demand should be dispatched from the dispatch schedule, in the same way as generators are today. We agree that yo-yo dispatch instructions for dispatchable demand providers will be relatively rare. However, a dispatchable demand provider subject to yo-yo dispatch could use the ability to rebid within the trading period to avoid being on the margin and therefore subject to yo-yo dispatch. We agree that such rebidding within the trading period (except during a grid emergency) would make them ineligible for constrained on or off payments.
Meridian Energy	We agree with the Authority's suggestion that dispatchable demand move from the non-response schedule (NRS) to the dispatch schedule. This move is dependent on Transpower's EDF Phase 3 project being implemented before real-time pricing. The move to the dispatch schedule is preferable to keeping dispatchable demand on the NRS, which would be more complex and less efficient.
MEUG	MEUG agrees with the proposal set out in paragraph 3.76 and 3.77 of the proposal paper to dispatch DD from the dispatch schedule rather than the alternative proposal to continue dispatch from the NRS subject to the Electronic Dispatch Facility (EDF)

Q13. What is your view on the best approach to incorporate dispatchable demand within an RTP framework? Please explain your reasoning	
	project being implemented to allow demand side participation without the need for a GENCO. MEUG suggests further work should be undertaken on the probability and magnitude of possible yo-yo dispatch for DD using in part lessons learned from NST experience as the sole DD participant to date and in part from scenarios of possible future DD participants. Then the solutions as discussed in paragraph 3.75 of the proposal paper such as including ramp rates and minimum cycle times for DD bids can be considered.
NZX	We have two issues with the proposed Code for dispatchable demand: *1. Revising a nominated bid in the trading period before the trading period to which the nominated bid applies:* In our view Clause 13.19A(3A) is no longer necessary. It was inserted to prevent erroneous constrained amount calculations where changes to nominated dispatch bids were made after dispatch instructions were issued from the NRSS (typically 27 minutes before real time). This should no longer be an issue given that DCLS are proposed to be dispatched from the dispatch schedule. *2. Constrained calculations for dispatchable demand purchasers* Clauses 13.194(1A) and 13.204(1)(aa) are incorrect and would not result in sensible constrained amount payments for dispatchable demand purchasers. We suggest that Qfp is calculated using bids and final prices in a similar manner to generator scheduled quantities. For a constrained off situation we suggest amending 13.194(1A) as follows: • Retain the existing definition of ConOffQ, • Amend the definition of Qfp as follows: Qfp is the bid quantity, in MWh, for the nominated dispatch bid price band if the **final price** is less than or equal to the **bid** price or is zero if, for the nominated dispatch bid price band, the **final price** is greater than the **bid** price, and • Amend the definition of Qdisp as follows: Qdisp is the **dispatched** quantity, in MWh, in the **trading period**, calculated under subclause (2), dispatched for the nominated dispatch bid price band in the trading period. For constrained on situations a similar set of amendments as above would follow for Clause 13.204(1)(aa).
Orion	We have no strong views. We do note, however that the prospect of and concerns about yo-yo dispatch may become more of an issue when and if

Q13. What is your view on the best approach to incorporate dispatchable demand within an RTP framework? Please explain your reasoning	
	increased unbid demand response occurs given the potential impact this will have on the SO's forecasts.
Pacific Aluminium	Agree with the proposal in paragraph 3.77 (i.e. a consistent approach for participants and generators).
Transpower	We defer to the responses of participants directly affected by the design choice.
Trustpower	We consider it makes sense to have generation and dispatchable demand in the same dispatch merit order and subject to the same dispatch compliance obligations. This will ensure a level playing field and will promote efficient market outcomes. Consistent with ensuring a level playing field, we consider it is important that the trading conduct provisions apply to dispatchable demand bids. We note the Authority's advice that this is anticipated to be completed prior to RTP commencing.
Vector	*The suggestion by the System Operator to include ramp rates and minimum cycle times for dispatchable demand bids may have merits if it can minimise rebidding within the trading period which can cause price volatility.*
WPI	*Design of Dispatchable Demand regime: DD would not give WPI price certainty if we decided to respond to a high price signal (as a DD participant) because WPI load cannot be controlled on a rapid response basis. We suggest that further work and consultation on the proposed DD design to reduce the current barriers to participation should be undertaken.*
IEGA,NZ Steel, Powerco	[No response to this question]

Q14. Do you agree with the proposed features for a dispatch-lite product? If not, please explain your reasoning	
Contact Energy	We are supportive of a dispatch-lite product (or other products that will increase the accuracy of the forecast schedules), but the consultation paper is short on detail (compliance and metering requirements) and we believe that more incentives are required to increase participation in DD. Dispatchable demand (or other products) should not be technology specific and should be able to be implemented with relative ease.
Contact Energy	***3. More Incentives and details are required for dispatchable demand lite*** *While we are supportive of a dispatch demand lite product, the consultation paper is short on information regarding implementation, and to ensure there are the right incentives to participate. Participation is important in order to address the issue of forecast inaccuracies due to non-scheduled demand reductions as mentioned in 1 above, and to encourage the use of emerging technologies and other demand based initiatives. The incentive to participate can be facilitated by constrained on/off payments, penalties, or by mandating under the code. In the absence of increased dispatchable demand lite participation, it is suggested that a reduction in the gate closure period is required to enable participants to better react to the real time price.*
EnerNOC	EnerNOC agrees with the dispatch-lite product proposal. However, if dispatch-lite is causing delays in the development of real-time pricing we believe that it should be removed or postponed until real-time pricing is implemented.
Flick Energy	The proposed features of the 'dispatch lite' seem positive. Flick is supportive of enhancements that would allow smaller (and new) participants to bid controllable load into market schedules. Noting that these participants would have lesser compliance obligations (and would not be eligible for constrained on and off payments). Obviously, how this will interact with system security is critical – and is best answered by those with working knowledge of these systems.
Genesis Energy	No, for the reasons provided as follows: Genesis fails to see the benefit of offering an alternative model to DD, which itself would become less onerous as a result of RTP, and cannot imagine there will be much appetite from consumers in the dispatch-lite product proposed, despite its catchy name. There do not appear to be any compelling benefits of dispatch-lite, particularly when offset against additional Code complexity and SO concerns discussed in section 3.5.2 of the RTP Report (TAS060). We recommend the Authority focuses on having a single, fit-for-purpose framework for DD, and prepares this for a future that will

Q14. Do you agree with the proposed features for a dispatch-lite product? If not, please explain your reasoning	
	be automated and software driven.
Mercury Energy	No. Mercury believes there should be one dispatchable demand product and one compliance regime. The best way to facilitate more demand response is to educate participants and provide them with the cost-benefit models and case studies to help with understanding the process. Relaxing compliance just removes any incentive for full participation in dispatchable demand which in turn undermines the system and does not encourage the discipline required for any future time when full compliance might be required.
Mercury Energy	*…we do not think the adoption of a new form of dispatchable demand for small bid purchasers (dispatch lite) will achieve the Authority's objective of encouraging consumers (or their agents) to directly participate in the spot market. Mercury agrees that greater participation from small bid purchasers is desirable, but our view is that the best way to encourage participation from small bid purchasers is to proactively seek out then educate participants and provide them with cost-benefit models and case studies. We consider that it is important that generation and demand are subject to the same compliance regime as any relaxation in the compliance requirements for demand runs the risk of enabling unhelpful habits to develop which would create uncertainty in the system when full compliance becomes mandatory in the future.*
Meridian Energy	It seems likely there will be minimal uptake of dispatch-lite. For now, it could be more efficient to focus on the critical design elements of real-time pricing, rather than spread resources more thinly. Dispatch-lite could always be added at a later date.
Meridian Energy	***Dispatch-lite*** *The Authority's attempts to facilitate demand-side participation though dispatch-lite are well intentioned. However, we question whether demand for these products exists in the market. Certainly the response from demand-side participants at the Authority's workshops suggested that uptake would be minimal or non-existent.* *Meridian's view is that dispatch-lite should not form part of the initial package of Code amendments introducing real-time pricing. Dispatch-lite could always be added at a later date if there is increased demand for such a product. For now, it seems likely to be more efficient to focus on the critical design elements of real-time pricing, rather than spread resources more thinly by also developing dispatch-lite.* *While we accept the Authority's position that there are minimal costs associated with the initial implementation of dispatch-lite, there is the potential for increased operational expenses to manage downstream compliance issues. For example, to monitor compliance with dispatch notices and decide who is eligible to participate in dispatch-lite.*

Q14. Do you agree with the proposed features for a dispatch-lite product? If not, please explain your reasoning	
MEUG	MEUG has approached this question by considering the benefits and costs to a non-conforming load deciding, in a RTP regime, whether to adopt DD-classic, dispatch-lite or neither. A summary of our analysis to date is in appendix A. There are no dollar values for listed benefits and costs and in any case, those may be purchaser specific. Nevertheless, we think it is worth continuing to explore if a dispatch-lite product can be developed in the next steps of implementing a final design for RTP. *[Appendix A is included on page 110.]*
NZ Steel	*a. DD lite. The concept proposed has possibilities, but requires further development before we can comment on its workability, particularly for large consumers.*
NZX	Yes. We recommend that a bespoke WITS interface for these participants is designed to facilitate and encourage the uptake of this market design feature.
Orion	We are not sure that compliance has any meaning in the context of dispatch-lite. How would anyone ever know that a dispatch “notification” had not been acted on? It certainly won’t be known in real time. As a consequence it appears conceivable that a dispatch light demand response bid could set the price even though that demand response never actually happens. While this looks like an opportunity for the demand side to manage prices down, it otherwise appears undesirable. On the other hand it may still be superior to the consequences of unbid demand response.
Pacific Aluminium	On the basis that the implementation cost of this feature is not material, then we agree.
Transpower	The system operator’s TAS060 report raised a concern for security (refer section 3.5.2) because of the potential for divergence of load bid and actual consumption. Further work with the Authority will be needed to understand any impact on, and possible mitigations for, system security.
Trustpower	Yes, we consider that the proposed features for a dispatch-lite product are reasonable. It does however seem counter-intuitive to have dispatch-lite set the price when they then may choose not to respond to the price signal. We acknowledge however that it is uncertain whether there will be many participants take up this offer as large industrial

Q14. Do you agree with the proposed features for a dispatch-lite product? If not, please explain your reasoning	
	loads will participate directly as dispatchable demand. As a result, dispatch-lite setting the price but not responding may be a rare occurrence. This matter could be considered during the post-implementation review of the proposed RTP arrangements.
Vector	*The dispatch-lite could have less onerous compliance obligations if subject to a rigorous approval process to ensure the price response intentions are credible enough to be relied on for forecasting and setting prices. 'Opting-out' of dispatch-lite bids by allowing revisions within the trading period should be limited to certain circumstances and any 'non-compliance' should impact on their approval status.*
ENA, IEGA, Powerco, WPI	[No response to this question]

Q15. Do you agree with the proposal to allow revisions to offers and bids within trading periods in some circumstances? If not, please explain your reasoning	
Contact Energy	Yes, subject to the same principles that are applied to existing technologies, being applied to any new markets/tech (bona-fide, or GE reasons)
EnerNOC	Yes, revision to offers and bids should be allowed within trading periods. EnerNOC believes that the current safe harbor provisions and high standard of trading conduct required in the market is sufficient to remove the possibility of participants gaming the market, for example by offer generation at a low price for the first 25 minutes of a trading period resulting in a high dispatch rate and then revising offers so that the price is greatly increased for the final 5 minutes of the trading period. EnerNOC supports a move to electronic revisions for offers and bids within trading periods to be adopted prior to the implementation of RTP.
Flick Energy	Flick is supportive of the proposal to allow revisions to offers and bids within a trading period – noting that these would only be limited to 'grid emergency or bona fide physical reason'. As the Authority has set out at 3.93 oversight and transparency would be key to ensuring that reoffers and rebids are not used to manipulate spot pricing.
Genesis Energy	Yes. Genesis notes that it advocates for all participants to be subject to the same behavioural expectations.
Genesis Energy	*We also have some concerns that confidence in the market may be undermined if there is not an even playing field for market conduct, which could in theory leave the door open to strategic bidding/offering.* *To counter this, it is important that there are equivalent behavioural expectations on all participants e.g. when it is permitted to revise bids/offers within trading periods. We note the Authority's compliance team will monitor participant behaviour to ensure there is no manipulation with the advent of RTP.*
Mercury Energy	Yes, as this will provide the most accurate information and reduce the amount of time-consuming verbal communication between participants and the system operator. Deviation events often go under the radar so the change would see them automatically included as revisions improving transparency. This change would need to be accompanied by robust scrutiny of participant behaviour from the Authority.

Q15. Do you agree with the proposal to allow revisions to offers and bids within trading periods in some circumstances? If not, please explain your reasoning	
Meridian Energy	Yes, if there is a bona fide physical reason or a grid emergency has been declared.
MEUG	Agreed and likely improvements in intra trading period forecasting and dispatch will exceed incremental cost to implement of between $25,000 to $50,000.
NZ Steel	*3. …variations to load bids inside Gate Closure are proposed by various means. However, each of these has unresolved issues/questions:* *a. Dispatchable Demand (DD). Currently there is only one participant. Despite 'tweaking', DD is still not seen as a workable option for other consumers. NZS participated in the initial trials, but the nature of our operations raised for us concerns that we could always meet dispatch-on instructions. As things stand DD is not a workable option for our site.* *b. DD lite. The concept proposed has possibilities, but requires further development before we can comment on its workability, particularly for large consumers.* *c. Demand side bidding and Forecasting (DSBF). While it appears this mechanism will remain, it is not clear currently as to its importance and how this actually works. The importance will change with non-conforming load bids to be included in the dispatch calculations.* *d. Bona fide physical reason. On the demand side there is lack of clarity as to how this applies now, and is proposed to apply under the proposed RTP regime.*
NZX	No comment.
Orion	No comment.
Pacific Aluminium	Yes, on the basis it remains for bona-fide physical reasons.
Transpower	Yes. The design element is an improvement on the current manual process for system co-ordinators, and should reduce risk of

Q15. Do you agree with the proposal to allow revisions to offers and bids within trading periods in some circumstances? If not, please explain your reasoning	
	any errors.
Trustpower	Yes, we agree with the proposal to allow revisions to offers and bids within trading periods where bone fide physical reasons exist or there is an emergency.
ENA, IEGA, Powerco, Vector, WPI	[No response to this question]

Q16. Do you agree with using the last bid or offer received in a trading period when calculating constrained on and off payments? If not, please explain your reasoning	
Contact Energy	Yes
EnerNOC	No, the average bid or offer for the trading period should be used for calculating constrained on and off payments. It is not clear how bids and offers across multiple tranches will be revised within a trading period.
Flick Energy	Flick notes that Authority is proposing to retain the constrained on and off payments process as market settlements remains on a 30-minute trading period using an average price. Flick agrees with this approach.
Genesis Energy	Yes, subject to the following comments: Genesis notes that constrained on/off amounts are paid by purchasers. This is a potential (perceived) complexity and market confidence issue for spot exposed parties, who may expect RTP to reflect actual spot market energy costs, when in fact they face variable spot market costs over and above the final price. One possibility to consider is incorporation of a small charge in final prices for demand to fund constrained payments and frequency keeping costs. While this may reduce the transparency of costs paid by spot-exposed consumers (although it would zero-out over time), it would ensure that the prices they see are as actionable as possible.
Mercury Energy	Yes
Meridian Energy	Yes
MEUG	Agreed
NZX	Using the last offer in the trading period could potentially result in large constrained on amount payments for participants that must revise their bids or offers due to, for example, a bona fide physical reason. This could result in perverse incentives for these participants. The response in the consultation FAQ that these types of events will be monitored by the Authority compliance team raises an enforcement issue as disputing whether a bona fide physical reason occurred may be difficult.

Q16. Do you agree with using the last bid or offer received in a trading period when calculating constrained on and off payments? If not, please explain your reasoning	
	This issue could largely be mitigated by calculating scheduled quantities on a time weighted average basis.
Orion	No comment.
Pacific Aluminium	Yes
Transpower	We defer to the responses of participants directly affected by the design choice.
Trustpower	Yes, we agree that the last bid or offer received in a trading period should be used for the calculation of constrained on and off payments.
ENA, IEGA, NZ Steel, Powerco, Vector, WPI	[No response to this question]

Q17. Do you agree we should retain a process for addressing material pricing errors? If not, please explain your reasoning	
Contact Energy	Yes. An automated error check process can be implemented for all common errors otherwise participants may lodge a pricing error if they are not happy with the scarcity or offer/bid price. The current UTS process needs to be retained as well.
EnerNOC	Yes, but the process must be transparent to all parties.
Flick Energy	Flick agrees that some checks should be retained for addressing material pricing errors (noting that errors have an adverse impact on the reputation of the market generally). Flick is supportive of a minimum materiality threshold (and of looking to other markets to consider this).
Genesis Energy	Yes, subject to the following comments: Genesis considers that managing rare events (i.e. material pricing errors) without undermining the benefits of RTP and maintaining confidence in the market is a challenge. We also note the definition of pricing error in the Code is "an error that is the result of an incorrect input being used or incorrect process being followed to calculate the interim price". A pricing error would, therefore, necessarily derive from either the SO or the Clearing Manager (**CM**) as the parties responsible for inputs and processes. The SO and CM would also be the parties most likely to make a pricing error claim, as they have visibility of the inputs and processes that other participants do not. This might mean the process is not that useful for participants other than the SO and CM, and begs the question we posed in the cover letter: if we can pinpoint the source of pricing errors, would it be better to address this instead, essentially solving the problem before it becomes a problem? Notwithstanding our comment above, if there is to be a process for addressing material pricing errors, we consider the design of this to be crucial, including how this should look over time once RTP has been bedded-in. We discuss this further in our response to Q18 below.
Genesis Energy	*With RTP aiming to provide timely and reliable information on spot prices, we have some concerns about retaining a modified form of interim pricing. Confidence in RTP could be undermined if available in 'real-time' means available 'at a later time' in the event of material pricing error claims. That said, we agree that having a process in place, of some kind, could be an important safeguard, particularly while RTP is new.*

Q17. Do you agree we should retain a process for addressing material pricing errors? If not, please explain your reasoning	
Mercury Energy	Yes
Meridian Energy	Yes
Meridian Energy	***Material pricing errors*** *Meridian agrees that it would be inefficient for the pricing manager to be retained solely to resolve pricing error claims.* *The System Operator holds the relevant expertise to efficiently investigate pricing error claims. However, as noted by the Authority, there is a clear conflict of interest for the System Operator. The conflict arises when the System Operator is required to investigate a claimed pricing error and the inputs generated by the System Operator[17] are material to the acceptance or rejection of the claim. In those situations the System Operator would be the judge of its own actions and this is clearly an inappropriate and invidious position for the System Operator to be in.* *We note that the drafting of the proposed Code amendments at clause 13.173C, appears to acknowledge the need for pricing error decisions to ultimately be made by the Authority:* ***13.173C Authority to decide whether pricing error has occurred*** *(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—* *(a) decide whether a material **pricing error** has occurred; or* *(b) if the **system operator** has advised the **Authority** to reject a claim, reject the claim.* *However, the current drafting is ambiguous and could imply that if the System Operator advises the Authority to reject an error claim then the Authority has no choice but to follow the advice and reject the claim. Meridian would like to see the drafting tightened so that the Authority is clearly able to accept or reject, at its sole discretion, the advice provided by the System Operator in the investigation report. We also recommend that the Authority has the ability to assess the situation using its own internal expertise, or alternatively an external expert.*
MEUG	Agreed

[17] For example demand forecasts, constraint design, or any discretionary actions undertaken by the System Operator in the running of the power system.

Q17. Do you agree we should retain a process for addressing material pricing errors? If not, please explain your reasoning	
NZX	No. NZX maintains that keeping the Pricing Error Claim (PEC) process will reduce participant price certainty. Clause 13.177(a) states that the clearing manager must recalculate interim prices as if the dispatch prices error had not been included in the relevant dispatch schedules. This does not allow for the system operator to correct for more systemic errors in the solve. In these cases reverting back to previous dispatch schedules may still not result in the desired outcome for more complex PECs. If the PEC process is to be retained under RTP to protect against manifest input errors we suggest that these should be resolved either using a previous dispatch schedule or a more drawn-out investigation by the system operator. Creating new response time requirements for both the Authority and system operator would give participants more certainty and faster resolution times for those PECs that can be resolved by using a previous schedule. Such timings could include that the system operator investigation specified in 13.170A have a 1800 hours deadline to conclude an initial investigation and send a recommendation to the Authority on whether the PEC can be resolved using a previous dispatch schedule or will require a more intensive investigation. By 1200 on the business day following the receipt of a PEC the Authority would be required to decide whether or not the PEC is legitimate. If the PEC was not legitimate then the Authority would advise the clearing manager and the original prices would be published as final. If the PEC was legitimate then either the Authority would direct the clearing manager to use a previously published dispatch schedule or update the market detailing why the issue will require a more intensive investigation by the system operator. For efficiency, improved robustness and timeliness NZX suggests that PEC processing by the clearing manager should be automated where possible. With regard to Clause 13.173.1(ca) and 13.173A we therefore propose that the system operator and Authority be required to provide advice to the clearing manager in the manner and form agreed by the clearing manager. The clearing manager would provide a suitable web form for this purpose. We also suggest that the materiality clause specified in clause 13.169 be defined in terms of a dollar amount to provide further guidance to the system operator and to prevent PECs disrupting settlement processes.
Orion	Yes
Pacific Aluminium	In the first instance yes. The need to address material pricing errors could be reviewed after a set period post RTP implementation, in order to determine if the need is still required.
Transpower	Yes. Transpower as the system operator is well placed to assume responsibility for the role.

Q17. Do you agree we should retain a process for addressing material pricing errors? If not, please explain your reasoning	
Trustpower	Yes, we support a process for addressing material pricing errors being maintained.
ENA, IEGA, NZ Steel, Powerco, Vector, WPI	[No response to this question]

Q18. Which approach do you prefer for managing pricing errors: a manual claim or automated checking? Please explain your reasoning (this could include suggestions for an automated filter)	
Contact Energy	As above, a hybrid of both manual and automated checking to weed out the most common errors.
EnerNOC	Automated checking of input data. This should be a percentage deviation from what the correct input data should have been. This is not comparing the input data with what actually happened but comparing if an error has occurred in the input data process. This will mean that it is less a measure of the price difference and more a check if there has been a material mistake in the input data. This is desirable because consumers will be making decisions on the dispatch price published at the time and confidence in these prices will be undermined if there are a number large price errors that are caused by small errors are cherry picked for intervention. It is EnerNOCs view that no party should have discretion to make corrections to prices should an error be identified. The process for correction must be predefined and transparent.
Flick Energy	The automation process that the Authority has cited that is used in the Australian National Electricity Market seems like a sensible process to borrow from. In general terms automation is preferable to manual processes. Obviously, this would require detailed design to ensure that automation is workable.
Genesis Energy	Genesis would prefer an automated process if inputs are corroborated. This could be coupled with a mandated random auditing process to ensure robustness. We can however understand that, at least initially, a manual process for managing pricing errors may be desired. As was stated at the 22 August workshop, this could provide an important ‘safety valve’ for the market under the new RTP regime. We are interested to hear other stakeholders’ views on this matter, and would be keen to ‘workshop’ the design of this process with industry e.g. take the opportunity to discuss, with our peers, what material might mean in this context. Genesis suggests materiality could be based on a whole-of-market cost deviation from ‘correct’ pricing rather than at an individual participant level, and should apply symmetrically to both under and over pricing errors.
Genesis Energy	*Genesis therefore believes the design of any process to be very important, key considerations of which include:* • *If we can pinpoint the source of pricing errors, would it be better to address this instead, essentially solving the problem before it becomes a problem?*

Q18. Which approach do you prefer for managing pricing errors: a manual claim or automated checking? Please explain your reasoning (this could include suggestions for an automated filter)	
	• *Should any process be a transitionary measure that can be phased out over time as participants grow comfortable with RTP?* • *How can we best define the minimum materiality threshold, given that 'material' might mean different things to different participants?* *We provide some thoughts on this in our responses to the consultation questions included below as Appendix A, but are very interested to hear other stakeholders' views and would like to see this worked on further, following this consultation.*
Mercury Energy	Mercury prefers manual checking because in our experience pricing error claims can involve issues where standard processes have broken down in subtly unexpected ways that automatic checks (such as thresholds for changes in price and flow) alone might not detect. Pricing error claims are also relatively rare and so a manual claim process will not overburden market participants. Mercury also believes that the definition of a "pricing error" warrants re-examination as part of the transition from today's arrangements to RTP. For example, the status quo interim pricing process requires a lot of information to be correctly input/re-input in the wake of prior schedules – be it actual demand, final offers, grid capability and so on. Some of this information is new information (e.g., metered demand) whilst some of this information is just copied across from a prior schedule (e.g., transmission constraint, grid capability, etc.) As a result, a pricing error claim under today's arrangements could (and has) simply centre(d) on whether the data from past schedules was re-input for interim pricing – transmission constraints being one such example. With the transition to RTP, errors occurring in interim pricing relative to prior schedules will be essentially impossible as dispatch prices will flow directly into interim pricing through time-weighted averaging. Therefore, the focus on pricing errors under RTP should shift somewhat. For example, the question as to whether the prior schedule's transmission constraint was copied across for interim pricing could become whether the grid capability inputs provided to the System Operator and/or the transmission constraints developed according to these grid inputs were sufficiently valid so that economically efficient dispatch occurred.
Meridian Energy	An automated checking process could be a first step to filter error claims and resolve anything obvious. A manual process will still likely be needed to resolve more complex pricing error claims. The Authority could review the use of manual claims after a couple of years and then determine if the need for manual claim still exists.

Q18. Which approach do you prefer for managing pricing errors: a manual claim or automated checking? Please explain your reasoning (this could include suggestions for an automated filter)	
MEUG	No view.
NZX	Both options for lodging PECs have their own merits and it is our view that a hybrid approach should be taken. Automated checking should be introduced, while still retaining the ability for participants to lodge their own PECs manually. Automated checking will provide greater certainty to the market and reduce the burden on participants to monitor final prices. By retaining the ability for participants to submit manual claims there would be a mechanism to address manifest input errors and where reverting back to a previous schedule would not address the underlying pricing error. Ideally the automated checking system would catch the majority of the PECs, however we believe that the manual claim process should be retained to act as an 'in case of emergency' lever for participants to pull. NZX also suggests that the causes for a PEC in Part 1 Preliminary provisions be amended to include: **pricing error** means an error in an **interim price** or **interim reserve price** is incorrect or is likely to be incorrect, as a result of— (a) an incorrect input being used in calculating the **interim price** or **interim reserve price**; or (b) the **clearing manager** having followed an incorrect process in calculating that **interim price** or **interim reserve price**, in contravention of this Code (c) the system operator having followed the incorrect process for inputs
Orion	A bit of both: automated as much as possible, but with manual intervention for unusual exceptions.
Pacific Aluminium	No firm view, however a two stage approach could be used. An automated check could be used to deal with the majority of 'simple' pricing claims and a manual price check used for the remaining/more complex instances (i.e. "80:20" approach). This approach could then be reviewed at set timeframes post RTP implementation to determine what on-going checks and balances are appropriate.
Transpower	The approach chosen may depend on understanding the likelihood of price error claims and assessing which approach is most cost-effective.

Q18. Which approach do you prefer for managing pricing errors: a manual claim or automated checking? Please explain your reasoning (this could include suggestions for an automated filter)	
Trustpower	We consider that a hybrid version may be optimal whereby an automated checking process like that used in the NEM could apply, but with an ability under exceptional circumstances to make a manual pricing error claim. Introducing a hybrid arrangement for managing pricing errors would provide assurances that there was an alternative manual arrangement for addressing pricing errors should the automated arrangement fail to identify an issue. A hybrid arrangement could act as a transition arrangement until market participants are comfortable with relying entirely on an automated process, though depending on the number of manual claims there may be value in maintaining a hybrid approach going forward. We consider that whether the hybrid arrangement should continue permanently should be further explored as part of the post-implementation review.
Vector	*In the long term an automated checking approach should be used for managing pricing. However, we suggest considering a bolt-on manual claim approach for a definite short term to deal with any RTP teething issues.*
ENA, IEGA, NZ Steel, Powerco, WPI	[No response to this question]

Q19. If we retain a manual claim process for pricing errors under RTP, who should perform that role: – the system operator? – the Authority? – the pricing manager, as their only function? – some other party? Please explain your reasoning, including regarding any possible conflict of interest	
Contact Energy	The Authority would be best placed to do this to remove any potential conflict of interest.
EnerNOC	The pricing manager (not necessarily the current pricing manager). This will insure the claims process to be undertaken impartially.
Flick Energy	As set out at Q18 Fick submits that automation would be preferable – however if manual processes are retained under RTP then they should be managed by the entity with the best current knowledge – which in that case would be the system operator.
Genesis Energy	Genesis considers the SO should perform this role, with a formal sign-off required from the Authority.
Mercury Energy	The System Operator should largely handle and investigate pricing error claims as they understand power system operation, inputs to the market system model and the workings of the market system the best. We have also observed that under today's arrangements, the Authority and the Pricing Manager have relied on the System Operator's insights for resolving many pricing error claims.
Meridian Energy	The System Operator holds the relevant expertise to investigate pricing errors. However, Meridian considers there to be a clear conflict of interest in situations where the System Operator investigates any pricing error claim where inputs generated by the System Operator (for example demand forecasts, constraint design, or discretionary actions) are material to the claim. In those situations the System Operator could be required to judge its own errors resulting in it being placed in an invidious position. Meridian supports the Authority retaining a role in the pricing error process. Ideally, the System Operator would investigate in the first instance and provide a report to the Authority. The Authority would then make the final decision (agreeing with or rejecting the recommendation of the System Operator). Meridian would like to see the drafting tightened so that the Authority is clearly able to accept or reject the advice provided by the System Operator in the investigation report. The drafting currently proposed does not achieve this outcome and seems to imply that the Authority is only a rubber stamp for any System Operator recommendation to reject a pricing error claim. Meridian does not support this drafting. Please also see the cover letter of this submission.
MEUG	No view.

Q19. If we retain a manual claim process for pricing errors under RTP, who should perform that role: – the system operator? – the Authority? – the pricing manager, as their only function? – some other party? Please explain your reasoning, including regarding any possible conflict of interest	
NZX	No comment.
Orion	We believe the SO is best placed, perhaps with the Authority in an approval capacity.
Pacific Aluminium	System Operator due to the points covered in paragraph 3.105, with the Authority making the final determination on any manual claims.
Transpower	Transpower as the system operator is well placed to assume the responsibility for investigating pricing error claims.
Trustpower	We consider that the Authority should undertake this function, subject to being able to meet the much tighter timeframes for investigating, advising, correcting and notifying the market of pricing errors (i.e. the next business day). There have been recent examples of this straightforward process taking more than two weeks to resolve which is suboptimal from an ex-post (let alone ex-ante) market perspective. Maintaining the pricing manager to carry out a small number of functions would be inefficient. Similarly, we consider that the system operator would be inappropriately conflicted in reviewing pricing errors given their new role in determining prices. There should however be no restrictions on the system operator identifying any potential pricing errors.
ENA, IEGA, NZ Steel, Powerco, Vector, WPI	[No response to this question]

Q20. Do you agree with the proposed treatment of spot prices during market system outages? If not, please explain your reasoning	
Contact Energy	Yes. We would like to see more rigour around planned outage publication information to make the RTP accurate.
EnerNOC	Yes
Flick Energy	Flick agrees that on the rare occasion that there is a market system outage that the process the Authority has set out at 3.107 (that prior prices would stand) is sound.
Genesis Energy	Yes Genesis notes that it agrees with the philosophy expressed in section 3.108 of the consultation paper. We should be aiming to make RTP as 'real-time' as possible.
Mercury Energy	Mercury cannot think of a better method than that proposed in the consultation document but we recognise that what is proposed is not optimal because it undermines the benefits of moving to RTP and therefore potentially dilutes the RTP approach. We are open to the Authority doing further work on this issue to see if a better solution can be developed.
Meridian Energy	Yes. However, Meridian encourages the Authority and System operator to take all reasonable steps to minimise the likelihood of a market system outage, including exploring technology solutions for backup market systems. Please also see the cover letter of this submission.
Meridian Energy	***Market system outages*** *Market system outages occur with surprising regularity – there is generally an outage of either the market system or the Wholesale Market Information System every month, sometimes multiple outages per month. Meridian estimates that these outages last for approximately 1.5 hours on average. We would appreciate it if the Authority (as the contracting party) or NZX would publish market outage statistics before real-time pricing is implemented.* *Meridian recommends that the Authority and System Operator take steps to minimise the occurrence and duration of outages. This could be a secondary backup that mirrors the live market system and takes over the market functions during an outage of the primary system, or some other solution. Given the criticality of the market system to system operations and the level of money exchanged through its operation, it is surprising that planned maintenance outages are still tolerable given the technology currently available. We appreciate that the risk of market system outages cannot be completely negated but would like to see more done to reduce the occurrence ahead of the introduction of real-time pricing.*

Q20. Do you agree with the proposed treatment of spot prices during market system outages? If not, please explain your reasoning	
MEUG	Agreed as there does not seem to be any other practical alternative.
NZX	Yes. For additional clarity we suggest that Clause 13.134A is amended such that the first sentence of second and third paragraphs are changed to “if there is no dispatch price or dispatch reserve price *at the time of calculation*”. This would cover the situation where: • One or more dispatch schedules for a trading period are not immediately available after the end of the trading period, • These missing dispatch schedules are subsequently published on WITS after the clearing manager has published interim prices. This could occur, for example, where there is an outage of the communication link between WITS or the clearing manager. In this scenario the system operator would still be preparing dispatch schedules and issuing dispatch instructions. Due to the communication link outage these dispatch schedules would in effect be queued for publication in WITS.
Orion	Yes
Pacific Aluminium	Yes
Transpower	Yes, we agree with the design as proposed (to use the last dispatch price, and to use the price responsive schedule (PRS) if the outage extends past the trading period).
Trustpower	Yes, we agree with the proposed treatment of spot prices during market system outages.
ENA, IEGA, NZ Steel, Powerco, Vector, WPI	[No response to this question]

Q21. Do you agree with the proposed changes to forecast schedules to align them with dispatch schedules? If not, please explain your reasoning	
Contact Energy	Yes
EnerNOC	Agree. EnerNOC also agrees with the view that following the implementation of RTP a stage 2 development should be to calculate forward schedules using 5 minute solves to better align the schedules with how final prices will be calculated.
Flick Energy	Flick is supportive of the proposed changes to the forecast schedules to align them with the dispatch schedules – noting that these schedules would provide prices which are 'like for like' with dispatch prices if forecast and actual conditions are the same.
Genesis Energy	Yes
Mercury Energy	Yes
Meridian Energy	Yes
MEUG	Agreed
NZX	No comment.
Orion	As we understand it, forecast schedules cover significantly more trading periods than real time scheduling, so it is unclear how far into the future this alignment will occur. Of more interest is how ongoing divergences between forecast and dispatch schedules are to be managed.
Pacific Aluminium	Yes
Transpower	Yes, we agree with the proposal for the forecast schedules to treat energy and reserve shortfalls the same as dispatch schedules. We also agree not to pursue (now) increasing the frequency of the forecast schedule to align with dispatch, and note the forecast uses only a single grid configuration for each trading period.

Q21. Do you agree with the proposed changes to forecast schedules to align them with dispatch schedules? If not, please explain your reasoning	
Trustpower	Yes, we consider that the proposed alignment of forecast schedules and dispatch schedules makes sense. Likewise we support considering a move to a 5-minute PRS-type forecast schedule in the future. This should be captured in the post implementation review of the RTP arrangements.
ENA, IEGA, NZ Steel, Powerco, Vector, WPI	[No response to this question]

Q22. Do you agree with the proposed use of dispatch schedules to apportion loss and constraint excess for financial transmission rights each month (if that is required)? If not, please explain your reasoning	
Contact Energy	Yes (along with any rebates).
EnerNOC	Yes
Flick Energy	Flick agrees with the proposed use of dispatch schedules to apportion loss and constraint excess for FTRs. Flick note the Authority's comments at 3.116 that the portion of LCE allocated to fund FTR has been growing over time as new FTR nodes are added. And at 3.117 that the proposed approach to apportion LCE would be 'consistent with the underlying philosophy used to apportion LCE under current arrangements'.
Genesis Energy	Yes
Mercury Energy	Yes
Meridian Energy	Yes
MEUG	Agreed
NZX	Yes
Orion	No comment.
Pacific Aluminium	Yes
Transpower	We assume the use of dispatch prices should not affect the current process for apportioning loss and constraint excess to financial transmission rights, but seek clarification on the process from the Authority.

Q22. Do you agree with the proposed use of dispatch schedules to apportion loss and constraint excess for financial transmission rights each month (if that is required)? If not, please explain your reasoning	
Trustpower	Yes, we agree with the proposed use of dispatch schedules to apportion loss and constraint excess. We understand that introducing RTP will be unlikely to change the current arrangements.
ENA, IEGA, NZ Steel, Powerco, Vector, WPI	[No response to this question]

Q23. Do you agree with the proposed approach for transitioning to RTP? If not please explain your reasoning	
Contact Energy	Yes, but this is subject to an update to the load forecast tool, EDF phase 3 implementation, and more incentives placed on DD Lite to participate in the market for RTP to be effective.
EnerNOC	Yes, however if delays are being caused by dispatch-lite it should be either removed or shifted into a secondary development work program.
Flick Energy	Flick note the comment that moving to RTP would involve significant changes to the current market systems. Flick is supportive of the idea of piloting RTP prior to full roll-out (given the importance of market security). Flick would encourage the Authority and the System Operator to wherever possible leverage existing technology from other markets rather than building technology. Four years seems like an incredibly long time.
Flick Energy	*Flick would encourage the Authority to consider ways to implement real time pricing sooner than the time frames indicated.*
Genesis Energy	Yes, subject to the following comments: While we appreciate that the four-year time allowed for transition to RTP is to accommodate SO market system changes, we strongly believe EDF phase three needs to happen as soon as possible. We consider GENCO to be sunset technology unfit for today's (and tomorrow's) electricity market.
Genesis Energy	***Next steps in the process*** *Genesis appreciates the Authority and the SO providing a four-year window to deliver RTP. While in a perfect world we would like to see the benefits of RTP sooner, we acknowledge that the timeline accommodates the significant changes needed to the market's systems and processes.* *During this time, we expect further engagement on the progress of RTP, an appropriate lead-time to prepare our own systems for integration, and opportunities to engage further with other stakeholders on detailed design considerations as they arise.*
Mercury Energy	Yes but Mercury would strongly support getting RTD prices published immediately to replace five minute RTP prices. We see this as a quick win as limited (if any) Code changes are required and the change would likely be relatively inexpensive. Mercury also supports a parallel pilot publishing RTP prices for 12 months prior to RTP going live so demand side participants can learn by doing and other market participants can also see how the system responds.

Q23. Do you agree with the proposed approach for transitioning to RTP? If not please explain your reasoning	
Mercury Energy	*Mercury would like the Authority to establish a technical working group made up of industry participants to assist with working through the design details for RTP. Mercury would be happy to provide a representative to participate in such a group. While the Authority is responsible for the overall project and Code changes we think it is important that as much input is provided by those who will be implementing and responding to the changes as possible. By the same token we believe it is crucial that the Authority and the System Operator run a twelve month parallel pilot when RTPs are published alongside the status quo so any problems with the proposed changes can be ironed out before the RTP package goes live.* *We support the System Operator publishing RTD prices now to replace or complement five minute RTP prices. We see this initiative as a quick win that can be implemented immediately as limited Code changes (if any) would be required and it could theoretically be done without incurring significant costs.*
Meridian Energy	Yes. In particular we support the publication of real-time prices on a pilot basis before they go fully live. Meridian encourages the Authority and System Operator to develop and run as many system components as possible in parallel to the current market system. For example, new demand forecasts could also be published on a pilot basis in advance of the go live date. We expect the Authority and System Operator to work closely with the industry during the development of an implementation plan (we note the further consultation signalled at paragraph 3.123 of the Authority's paper) and subsequently during the implementation period to keep participants informed of progress and anticipated timing. The more certainty participants have, the more efficiently we will be able to prepare our own systems so that we can engage effectively with real-time pricing on day one. The work involved to transition our own internal systems and processes is not insignificant. Please see the response to question 25 below for an early estimate of costs.
Meridian Energy	*The move to real-time pricing will be a significant change to the operation of the spot market. While we agree with the proposal in principle, it will be challenging to implement in practice. The Authority and the System Operator will need to implement the proposed changes in a timely fashion and in a way that gives market participants confidence that the platform will operate as anticipated on day one.* ***The implementation process*** *In general, Meridian supports any efforts to increase confidence and certainty in real-time pricing so that participants can adapt their systems and be ready for the go-live date. We encourage the Authority and System Operator to work closely with the industry during the implementation period to keep participants informed of progress and anticipated timing. Market participants have also built a number of processes and systems that will need to be adjusted when real-time pricing is implemented.* *Meridian appreciates the Authority's stated intention is to publish the new real-time prices on a pilot basis before they go fully live.*

Q23. Do you agree with the proposed approach for transitioning to RTP? If not please explain your reasoning	
	Meridian encourages the Authority and System Operator to develop and run as many of the real-time pricing system components as possible in parallel to the current market system. This will enable participants to see in advance how the system might work and prepare us to operate under the new market system. A beta system running in parallel need not operate in real time; hindcasting could be used and components of the system modelled if needed. Anything that can be achieved in this regard will increase participants' certainty and help to smooth the transition to real-time pricing. *Finally we note that the Authority's workshop presentation for the proposal indicated that a Board decision would be made in December 2017 but that any agreed Code amendments would then be "parked" until mid-2020, when the Authority is contemplating a further "optional Code amendment consultation" before publication of final amendments in the Gazette. In Meridian's view this process is not appropriate. A gap of two and a half years between a decision and publication in the Gazette means that further consultation should be mandatory. We urge the Authority to commit to such consultation now. Alternatively the necessary Code amendments should be published in the Gazette soon after the Board decision in December 2017, with a deferred date for coming into force. This alternative could also require a second round of consultation on Code changes that arise in the course of implementation work of the following two years.*
MEUG	Agree with implementation of phase 3 of the electronic dispatch facility (EDF) prior to RTP going-live, implementing RTP using a staged approach and publishing new RTP prices on a pilot basis. In addition, MEUG suggests RTP will be enhanced by other complementary work by the EA on: a) Work programme A8 Enabling dispatchable demand at conforming nodes.[18] The benefits of RTP will be achieved quicker if there is at the outset a pool of purchasers already in the existing DD regime or are ready to take advantage of the options to be able to actively manage demand side response. Work programme A8 is one means of increasing that pool of purchasers ahead of RTP starting. b) Investigating how WITS data could be made more actionable ahead of RTP being implemented.[19] The purpose of this tactic is identical to work programme A8 above, i.e. to increase the pool of purchasers that can actively manage demand side response ahead of RTP starting and therefore realise the benefits of RTP quickly. *c)* Improving the accuracy of demand forecasting for non-conforming nodes. The EA has work planned (Project C6) to improve the accuracy of spot price forecasts with an initial focus on conforming loads.[20] MEUG suggests that project be expanded to consider how to improve spot pricing forecasts for non-conforming load for non-dispatch-capable load (ie not in DD market).

[18] A8 is a priority 3 project in Programme A: Evolving technologies and business models. A8 is described as "A project to enable aggregators to aggregate load over several conforming GXPs and several retailers. This involves an expansion of the dispatchable demand (DD) regime" and the reason for doing the work "We are seeking to enable more efficient use of dispatchable demand by allowing third parties to contract with loads at conforming GXPs. This will improve competition and reliability." Refer http://www.ea.govt.nz/dmsdocument/22305

[19] For example, there might be scope for an improved Application Programming Interface (API).

Q23. Do you agree with the proposed approach for transitioning to RTP? If not please explain your reasoning	
	Some non-conforming nodes are: ~ Small relative to conforming nodes; ~ Situated where grid constraints are rare; and. ~ Most demand uncertainty is due to unplanned trips and therefore usually no or minimal system risk (risk is asymmetric). In these cases. the current requirements for non-dispatch-capable load at non-conforming nodes to make nominated non-dispatch bids and revise those if expected volumes exceed pre-set ranges in cl. 13.19B impose material compliance costs with possibly no net benefit to NZ Inc. This is often abbreviated as the "DSBF" requirements.[21] This compliance burden has undermined the confidence of some purchasers at non-conforming nodes to consider spending effort and resources to more actively participate in demand side response using DD – why spend more money when they are already spending money on DSBF compliance with no obvious benefit to them or the market? MEUG suggests using external near-term demand forecasting techniques for small and rarely critical non-conforming nodes may be more accurate and cost effective than the current DSBF approach; hence expanding EA Project C6 to include both conforming and non-conforming nodes should be considered. d) Providing prospective dispatchable demand (DD) participants information on the pros and cons of DD as a way of realising any potential DD earlier rather than wait until RTP implemented. MEUG members benefited from the EA monitoring team work alleviating concerns that under the current DD regime suppliers could and would shadow DD bids. Part of the benefit of being a DD participant is having spot price certainty by way of constrained on and off payments. MEUG believes potential DD participants would benefit from understanding the frequency and value of constrained on and off payments to NST over the last few years; excluding the initial period before the code was amended to overcome initial design problems with those payments. A review of the performance of the existing DD regime would also assist in considering possible future yo-yo dispatch risk as discussed in response to Q13 above.
MEUG	*This consultation has provided the detail the industry has needed to test alternative aspects of the design and proposed code amendments. It's fair to say we approached this consultation with the view that the "the-devil-is-the-details." We have benefited from extensive and intensive discussions with EA, System Operator and advisors to the EA (Concept Consulting) staff to address*

[20] Project C6, Improving accuracy of spot price forecasts, a priority 2 project in Programme C: Pricing and cost allocation. Project C6 is described as to "Improve the accuracy of prices in the spot market forecast schedules available up to 36 hours in advance of real-time" and the reason for doing the work "We want to reduce barriers to retail competition and demand response arising from current spot market arrangements. Improving the accuracy of spot price forecasts is expected to encourage more efficient demand-response and generation scheduling, and benefit those parties looking to employ new technology and business models." Refer http://www.ea.govt.nz/dmsdocument/22305

[21] Cl. 13.19B also has DSBF requirements for a dispatchable load purchaser making a nominated dispatch bid (ie a DD bid). MEUG has no concerns with that limb of the DSBF requirements.

Q23. Do you agree with the proposed approach for transitioning to RTP? If not please explain your reasoning	
	our questions. In this submission, we suggest further details in addition to those discussed in the consultation paper we think need to be considered as design is finalised and implementation can commence. *In summary MEUG supports continuing to work on finalising implementation details to introduce RTP.* *Implementation details for further consideration fall into three categories. First, those the EA sought views on in the proposal paper. Second, new details arising in this consultation round. Third, complementary work that will enhance or make benefits of RTP realised earlier. Appendix B of this submission lists key implementation details affecting customers in a RTP regime participating directly in the wholesale market for each of those categories. The list cross-references where those topics are discussed in this submission or other sources.* *[Appendix B is included on page 111.]* *In conclusion MEUG supports continuing to work on finalising implementation details to introduce RTP.*
Mercury Energy	*…we would appreciate the opportunity to comment on the draft Code amendments again when they are revised following this round of consultation. It is important that the requirements of the new regime are as clear and accurate as possible.*
NZX	The creation of a five year project to implement RTP creates potentially significant operational and reputational risks to the New Zealand electricity market. Historically large scale projects risk coming in over budget and experience substantial implementation risks once they go live. NZX agrees with Transpower that single stage development and commissioning introduces an unreasonable amount of risk to the market. Transpower's broad categorisation of the project into four stages with four implementation phases will help mitigate these risks. However, it is our view that the delivery phase that Transpower has proposed does not go far enough. Projects of this scale need to deliver value early and often to reduce risk and there are many issues with the current pricing process that can be pursued independently and concurrently with RTP to reduce participant's price uncertainty. An example of this is improving forecast demand schedules or addressing the causes of provisional pricing situations under the current pricing methodology. There are currently a number of pricing situations (metering situations, infeasibilities, high spring washer situations, and scarcity price situations) that occur that decrease price certainty for participants by causing prices to be published as provisional. Using metering situations as an example, the introduction of ion meters as detailed in 3.71 of the consultation paper as the primary source of load metering could eliminate metering situations as a cause for provisional prices entirely. Changes like these should be prioritised as they are an intermediary step for RTP and will increase price certainty for participants during the lengthy transition phase.
Orion	No comment.

Q23. Do you agree with the proposed approach for transitioning to RTP? If not please explain your reasoning	
Orion	*We believe that for a change of this magnitude a further round of consultation is desirable before the Authority makes a final decision.*
Pacific Aluminium	Yes. Support running & publishing prices under a RTP pilot in parallel with the current system, to enable participants to determine any potential pricing impact.
Transpower	Yes, we support the Authority working with the system operator to develop a detailed implementation plan (after the Authority Board has approved the RTP design).
Transpower	***Support continued transparency for policy and design choices*** *Given the scope of the project, engaging a third-party to facilitate a risk-management workshop between Transpower and the Authority was beneficial to the development of design and process.* [22] *The workshop assessed project complexity, reviewed how complexity should be managed, and created alignment between the Authority and Transpower on project challenges. The workshop also helped develop a shared understanding of the likely timeline for implementation, including adopting a phased approach to de-risk project delivery. Making the project's risk and assumptions register available with the consultation paper has provided welcome transparency and clarity for many of the design decisions.* *We encourage continuing dialogue with industry to enable the implementation phase of the real-time pricing design. We suggest a working group could be created to support the selection of robust design choices that are practicable and minimise the risk of costly and disruptive re-work. Equally, the group would help communicate with wider stakeholders so that they are engaged, informed and well-prepared for when the system goes live.*
Trustpower	Yes, we support the staged implementation of RTP over four years. This will enable sufficient time to develop the required new systems, processes and hedging instruments (if required). We consider there will be significant value in undertaking a parallel run during the transition period so that impacted parties can understand how pricing outcomes would vary in reality from the current arrangements. This would also enable any potential issues to be identified and addressed prior to official "go-live". We note that the Authority is considering whether it would be possible to publish notional "real-time" prices in the lead up to the RTP going live.

[22] System operator report TAS060 Chapter 7

Q23. Do you agree with the proposed approach for transitioning to RTP? If not please explain your reasoning	
ENA, IEGA, NZ Steel, Powerco, Vector, WPI	[No response to this question]

Q24. Do you agree with the objective of the proposed Code amendment? If not, please explain your reasoning	
Contact Energy	Yes, but as per Q23 this is based on full participation of biddable demand
EnerNOC	Yes
Flick Energy	Flick is absolutely supportive of the objective of the proposed amendment to make spot prices more actionable and resource efficient. Flick believe that this consistent with the Authority's statutory objective – and as the Authority has set out - will 'remove barriers and will promote the uptake of new technologies and new business model'. Allowing customers to realise benefits that are not available currently.
Genesis Energy	Yes
Mercury Energy	Yes
Meridian Energy	Yes
MEUG	Agreed
NZX	Yes
Orion	No comment.
Pacific Aluminium	Yes
Transpower	Yes, to make spot prices more actionable and resource efficient.

Q24. Do you agree with the objective of the proposed Code amendment? If not, please explain your reasoning	
Trustpower	Yes, we support the assessment against the statutory objective.
ENA, IEGA, NZ Steel, Powerco, Vector, WPI	[No response to this question]

Q25. 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 effect/level of demand response will only improve if the current barriers to participation are removed and there is sufficient incentives to participate whether it be economic or mandatory. Without participation of all demand capable of being shed into the market there will be little or no improvement in the forecast price or the lessening of the saw tooth pricing we see under tight market conditions at present. To further increase the benefit of RTP the EA should review whether a further reduction in the gate closure period to 30 minutes would result in more accurate pricing.
EnerNOC	It is difficult to comment on the assumed quantity of demand response due to the lack of retrospective analysis RTP will have on the 'peakyness' of prices. EnerNOCs international experience leads us to believe that the base case assumptions in regards to increased demand response are of an optimistic nature.
Flick Energy	Flick is broadly supportive of the cost benefit assessment. Flick also notes that the Authority has identified that RTP could provide additional benefits in that under RTP prices are less likely to be closer reflect the true value of energy and reserve – and that with this would come increased confidence in the market and would lead to better informed confidence in the value of risk management products. Although true impact of increased technology such as batteries cannot be accurately modelled into cost benefit analysis it is positive that these technologies would be better implemented with RTP.
Flick Energy	*Flick has noted that there is an increasing number of residential customers who are willing to actively respond to price signals. Making these price signals known in real time would be well received, and beneficial to these customers.* *With the pace of technology advances, price certainty is critical to allowing customers to make demand response (and generation and consumption) decisions.*
Genesis Energy	No comment.
Genesis Energy	***Future proofing net benefits for consumers*** *Genesis agrees that the flow-on effect of more certain and actionable prices for generators and purchasers in the market will*

Q25. 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	
	deliver net benefits to consumers. Having greater confidence that 'what you see is what you get' regarding prices should enable more efficient generation scheduling, and there will potentially be significant benefits for switched-on consumers who are willing to change their behaviour in response to price signals. *We note that improved demand response is the expected main benefit from RTP. Genesis believes that in the future technological advancement will see demand response become more automated, giving rise to lower barriers to entry for a raft of potential demand-side participants.* *We urge the Authority and SO to reflect on whether its proposed market design can accommodate what demand response might look like in the future e.g. automated household level demand-side participation in the thousands. No one can foresee the future, but it would be unfortunate to find ourselves locked-in to a market that only anticipated demand response from large-medium consumers or load aggregators.*
Mercury Energy	Mercury has not assessed the cost benefit in detail. We strongly believe moving to the RTP regime will be good for the NZ electricity market for the reasons outlined in the consultation paper. We do not think that participant implementation costs will be zero and we consider that demand side participation will possibly lead to fewer benefits than estimated.
Meridian Energy	Quantified benefits are derived from more efficient demand response, based on the belief that this will improve if participants have access to reliable price signals. This is a significant assumption and we agree with the Authority's statement that, "there is considerable uncertainty about the amount of demand-response that RTP will unlock." The cost benefit assessment states that implementation costs for participants would be $0. We disagree with this assessment. Changing Meridian's systems and processes to accommodate real-time pricing will be significant. Our early estimates are that a three month project could be required, involving one-off costs of approximately $390,000.
MEUG	MEUG agrees with the conclusion in paragraph 4.22, "In light of the overall analysis, we think there are strong grounds to expect RTP to provide positive net benefits."
MEUG	*We agree there is likely to be a material positive economic benefit.*
NZX	No comment.

Q25. 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	
Orion	We are uncertain that any increased demand side response will necessarily be more efficient. If it makes load inherently more difficult to forecast, and inherently less stable in real time, it may decrease efficiency.
Orion	• *We believe that the benefits may be overstated.*
Pacific Aluminium	Yes
Transpower	We consider the CBA is likely to understate the costs of introducing RTP. For example, the cost analysis should recognise participant adaption costs, as raised in TAS 60 [page 22] "Such a wide-reaching and complex change brings inherent risks. To implement RTP would also require many external parties (e.g. service providers and market participants) processes and systems to be modified." For the grid owner, for example, the time and costs of any reconfiguration of the IONS meters would need to be included.
Trustpower	We have not gone into detail in reviewing the cost benefit assessment presented by the Authority but we do consider it is likely that the changes will lead to positive outcomes. We have raised some concerns directly with the Authority around the need for a more granular simulation of spot market outcomes (i.e. a more detailed hindcast for each trading period, rather than just those involving infeasibilities or spring washers). There could be adverse impacts on some specific consumers at constrained nodes. We are interested in better understanding this impact at each GXP, including a quantified effect.
ENA, IEGA, NZ Steel, Powerco, Vector, WPI	[No response to this question]

Q26. Do you agree with our assessment of alternative RTP designs? If not, why not?	
Contact Energy	Yes
EnerNOC	No EnerNOC does not believe that sufficient assessment of alternative RTP designs has been undertaken. While the consultation completed looking at four real-time pricing options has clearly ruled that a look-ahead 5-minute dispatch-based price is the most favourable option. There is little information available that sufficient investigation has taken place looking at the possible options within the look-ahead 5-minute dispatch-based price solution and options may have been ruled out as to costly without adequate analysis.
Flick Energy	Flick agrees with the reasoning and the Authority's assessment of the alternative RTP designs.
Genesis Energy	Yes
Mercury Energy	Yes, see our submission on the previous round of consultation.
Meridian Energy	Yes
MEUG	Agreed. Nothing has changed since the EA consulted on this in April last year.[23]
NZX	No comment.
Orion	As noted above, actions take time, and the proposal seems to us to have shortened the available time to as little as it can possibly be without it being zero. We consider that the paper has not adequately shown that this is superior to Option A, or some variant of Option A. Para 4.25 of the paper points to Option A being an "ahead-market", which is true, but so is the proposal, it's just less ahead and for a (probably) shorter period. The same para also notes that "a lot can change in 30 minutes", which is certainly true, but a lot can change in, say, 5 minutes as well. Whether "a lot" is more or less under the proposal than it is now remains to

[23] Refer http://www.ea.govt.nz/dmsdocument/20599

Q26. Do you agree with our assessment of alternative RTP designs? If not, why not?	
	be seen.
Pacific Aluminium	Yes
Transpower	In our previous submission on the options presented for Real Time Pricing, we wrote " the quantified CBA as a tool for assessing between options would need to articulate the trade-offs or features such as certainty, accuracy and the potential for gaming, as well as costs". No new information was presented in this consultation paper to understand how the trade-offs were made. We note that the option chosen is the highest cost with a long implementation time; there will be an opportunity cost associated with the selected option over other less complex approaches. We consider that the Authority should satisfy itself that the right balance has been struck between cost, complexity and benefits.
Trustpower	Yes, we agree with the Authority's assessment that Option B (the current dispatch-based RTP proposal) is the best alternative. Refer to our previous submission on "Assessment of real time pricing options"[24] for further details of our views around the alternative RTP options. We note that the majority of submitters (13 out of 15) supported option B during this previous consultation.
ENA, IEGA, NZ Steel, Powerco, Vector, WPI	[No response to this question]

[24] http://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/exploring-refinements-to-the-spot-market/consultations/

Section 2 Comments on issues other than specific consultation questions

General support (or otherwise) for RTP	
ENA	*ENA members support the Authority effort to make the energy market to be dynamic with real time pricing, allowing the market to be more responsive to the changing sector.*
EnerNOC	*While EnerNOC supports the market development to an ex-ante price that is both actionable and reflective of the system conditions at that point in time, we believe that areas of the Authority's proposal will lead to both market inefficiencies and higher compliance cost for some participants. In particular the proposed time-weighed averaging of dispatch prices, incorporation of dispatchable-demand in a real-time market and the integrating of non-conforming GXPs DSBF requirements into a real-time market.*
Flick Energy	*Flick reiterates prior submissions made, in particular that we are supportive of the Authority's work to make spot prices more actionable and resource efficient*
Mercury Energy	*We congratulate the Authority on the quality of its work on this project to date and look forward to working closely with the Authority during the design and implementation stages. We see this as an important project, which providing industry participants and the Authority work together constructively, should deliver significant improvements over the status quo and bring us into line with most other countries and help future proof the electricity market as new technologies such as battery storage and smart appliances are deployed.*
Meridian Energy	*Meridian supports the proposal in principle and agrees that real-time pricing will provide greater certainty and enable parties to make more efficient, real-time decisions about their consumption and generation of electricity. In principle, real-time pricing is preferable to the current process, whereby final prices are published at least two days after real-time.*

General support (or otherwise) for RTP	
MEUG	*Progressing RTP to a point where decisions can be made for implementation has been a top priority project for MEUG for many years. RTP has always been our preferred long- term development path for the wholesale market. We welcome the EA deciding to step away from further work on a mandatory ex ante market.*[25]
NZ Steel	*New Zealand Steel (NZS) supports the work of the Authority to improve the pricing signals provided under the current ex-post mechanism. We have also expressed support in principle for a Real-Time Pricing (RTP) regime.* *We are mindful of the Authority work programme "Improving the accuracy of spot price forecasts". The current RTP proposal contains elements that will also assist in improving the accuracy of predicted prices, in addition to the real-time price calculation. However, the way it is proposed to achieve the RTP regime raises some issues and concerns:* *1. The proposal is for a 5-minute ex-ante calculation of unit price. The inputs (supply and demand) required for this calculation bring into question whether this is in effect RTP. Our comments largely focus on demand side non-conforming GXPs.* *The concept of RTP is supported by NZS. However, what is being proposed does not appear to be a real-time option for consumers at non-conforming GXPs.*
Orion	• *We support the proposal, in broad principle.*
Pacific Aliminium	*NZAS supports the Authority's proposal to implement real-time pricing. We believe the proposal should enable load management decisions to be made with more confidence than is possible under the current pricing structures.*
Powerco	*We support the concept of real-time pricing.*
Transpower	*We submit in our capacity as grid owner and system operator and note the extensive input of the system operator in the development of the preferred option, prices in real time based on dispatch ('option B').*

[25] Refer EA decision paper, Making price forecasts more accurate, 15 August 2017, http://www.ea.govt.nz/dmsdocument/22436.

General support (or otherwise) for RTP	
Trustpower	*The Consultation Paper proposes moving to real-time (ex-ante) pricing for the spot market (**RTP**). Final prices for the spot market would be determined and published in real-time based on the system operator's dispatch process. This will provide parties with timely and reliable information in advance on the prices they will receive/pay for their spot market transactions.* • *We are generally supportive of implementing the proposed RTP arrangements, as providing ex-ante price certainty can be expected to:* a) *Result in more efficient, short and long-term decision making by all market participants;* b) *Enhance confidence in the market's outcomes; and* c) *Further support the adoption of more innovative solutions to changing system conditions such as the installation of batteries.*
WPI	*WPI supports the Major Electricity Users Group's (MEUG) submission on this consultation paper…*

Interaction of RTP and TPM	
Vector	***Interaction with transmission pricing methodology*** 2. *We are surprised the Authority has suggested there is no interdependency between the RTP and its proposed changes for the TPM in its frequently asked questions on the RTP Consultation.* 3. *We understand the move to real time pricing (RTP) for the wholesale market will have implications for the Authority's transmission pricing methodology (TPM) proposal. The Authority's most recent proposed TPM guidelines, as part of its TPM reform, referred to wholesale market pricing. Accordingly, we are concerned such matters were not discussed in the RTP Consultation itself. This is especially the case given RTP is expected to be a significant reform to New Zealand's wholesale market.* 4. *The Authority's proposed TPM guideline created a requirement for Transpower where it considers applying a long-run marginal cost (LRMC) component to the Authority's proposed TPM reform. Where Transpower considers an LRMC component for TPM then it must demonstrate the LRMC pricing signal is "over and above" the signal provided by wholesale nodal prices and other transmission charges.* 5. *Given RTP is a significant change for wholesale nodal prices then it will have an impact on TPM. Specifically, any change to Transpower's capability of applying an LRMC as a result of a move to RTP should be acknowledged*

Interaction of RTP and TPM	
	10. We recommend the Authority disclose the interactions of the RTP with its proposal for TPM reform so that stakeholders are fully informed of the consequences for the Authority's TPM proposal.

Demand forecast accuracy	
Meridian Energy	***Demand forecast accuracy*** *For the forecast schedules, Meridian submits that the demand forecast should meet a high standard of accuracy (i.e. a higher standard than current forecasting) and that the methodology for determining the forecast should also be transparent and tested to measure its accuracy on an ongoing basis. Again we consider this to be a prerequisite for the introduction of real-time pricing. As real-time pricing will give more certainty to demand response and new technologies, the forecast schedules should also give improved certainty to those participants that are subject to the one hour gate closure. Ultimately this will improve all market participants' decision-making. Meridian expects that demand forecast improvements would be consistent across all the schedule horizons, not just in the dispatch schedule. Failure to have consistency across schedules would result in final prices diverging from forecast prices, undermining the expected benefits to the consumer.*
NZ Steel	*2. The real-time unit price would be derived from the forecast load and available supply. The forecast load component of this equation requires further consideration:* *a. Pricing is a combination of volume and unit price. The unit price determined by the SO pricing model is only part of the equation.* *b. Conforming nodes have predicted load calculated by the SO. We note however, the Authority work has shown conforming load to have the largest variation to actual[26] . Until the project of work to address this issue is completed, it will impact on the RTP regime proposed.* *c. Non-conforming GXPs are required to nominate load and price on a half-hourly basis before gate closure ie one-hour*

[26] Electricity Authority, "Making hours-ahead price forecasts more accurate", Consultation paper, 9 February 2016.

Demand forecast accuracy	
	out. The current and proposed mechanisms for altering load bids within gate closure are far from clear. *d. The result is consumers at conforming nodes get the full benefit of RTP ie the price is know before (and during) each trading period and load can be varied at will.* *e. For non-conforming GXPs we suggest what is being proposed is not RTP. The unit price will be known, but consumers at these GXPs need to meet certain (unclear) criteria before the load nominated an hour before the unit price is determined, can be varied.* *f. Given a. & b. above, RTP as proposed disadvantages consumers at non-conforming GXPs and there are no immediate plans to address the issue of conforming loads impacting the supply/demand equation, nor to further reduce Gate Closure.* *The issue of inaccurate load forecasting at conforming nodes has not been resolved and is hindering pricing forecasts. (we note the Authority work programme includes "Improving the accuracy of spot price forecasts").*
Orion	***Other Authority projects – demand forecasting,*** *37. We believe the real-time pricing proposal interacts with the Authority's demand forecasting proposal in some very important ways:* • *The relationship between short term demand forecasts (say for the next 48 trading periods) and dispatch forecasts needs to be understood.* • *Improvements to forecasting (all forms) need to consider how existing and possible new demand response will be factored in.*

Other comments	
ENA	*Our submission takes the form of a letter because the consultation paper only indirectly impacts ENA members. We say this because EDB's do not directly participate in the wholesale energy market where this proposal is targeted, but they do directly provide demand response, and indirectly enable other demand response that is bid into the market.* *EDB's are however acutely aware that because the electricity sector is undergoing quite some change, current markets need to*

Other comments	
	adapt to these changes and that EDB's also need to be aware of and respond as the changes progress.
Flick Energy	*Flick reiterate that actionable prices are an enabler of retail innovation.*
Genesis Energy	*The move to real-time pricing (**RTP**) will fundamentally change the ways spot prices are calculated in the New Zealand electricity market requiring substantive amendments to the Electricity Industry Participation Code 2010 (**the Code**).* *We are pleased to see the Authority and System Operator (**SO**) acknowledge this and prioritise engagement with industry stakeholders as to the optimal design and delivery of this project.*
IEGA	*The IEGA comprises about 40 members who are either directly or indirectly associated with predominantly small scale power schemes connected to local networks throughout New Zealand for the purpose of commercial electricity production.*[27] *All but one of our members does not currently dispatch their generation in the spot market. Given the capacity of individual plant this is consistent with the requirements in the Code. The threshold in the Code was put in place to acknowledge the additional compliance and overhead costs of dispatch in the spot market. The threshold continues to be relevant as our members do not have the physical (or financial) resources to manage a 24/7 'trading' activity. We are price takers and have historically responded primarily to transmission and network peak pricing signals through the Part 6.4 payment mechanisms. Changes to Part 6.4 and future changes to the TPM mean our membership may be interested in dispatch if there is clearly value from participating.* *The IEGA understands the benefits of clearing the spot price in real time and having actionable prices in the spot market. However, we seek more clarity about the RTP proposal in relation to distributed generation (DG) and how DG can 'participate' or receive revenue under the proposal.* *We have outlined our concerns and questions by responding to some of the questions asked in the Consultation Paper – see below.* ***Summary of our main points:*** *1. DG owners with plant capacity under 30MW have effectively been excluded from the RTP design process.* *2. DG needs a mechanism like Dispatch-Lite and to be able to bid volumes on the supply side to ensure equal market participation.* *3. DG should not be included in the net GXP demand forecast as it is a competitive and discretionary bid option. Demand*

[27] The Committee has signed off this submission on behalf of members.

Other comments	
	forecasts should be at gross GXP demand (excluding DG and DR). 4. *DG and DR not dispatched should be allocated scarcity prices on opposite sides of the market. This then ensures transparency and information symmetry for price discovery.*
Mercury Energy	*While Mercury supports the proposals we have a number of concerns. First, we think it will be important for the Authority to carefully consider how it will monitor participant behaviour under RTP to ensure that any gaming behaviour is minimised. For example, the time-weighted average aspect and the opportunity to revise offers during trading periods. Mercury would like the Authority to give more consideration to how it will scrutinise RTP in practice.* *This may involve allocating resources specifically to increased market monitoring and surveillance in the initial period when the new system is bedding in.*
NZ Steel	38. *Underlying the current DD regime is a concern anecdotally that load and price bids from non-conforming GXPs are in effect setting the price. While we can understand this will occur in a minority of situations when that bid is at the margin, the concern is DD has moved from a price the demand side is not prepared to pay greater than, to a price load side is prepared to pay. This is at variance to the purpose of DD - "Dispatchable Demand (DD) was introduced to the wholesale electricity market to enable demand-side participants to have certainty over consumption decisions and to put downward pressure on spot prices"* [28]*. We await the result of the current Authority enquiry into the matter of demand side price bids setting the price at that GXP.* 39. *One hour Gate Closure and discrete 30 minute Trading Periods exacerbate the situation outlined in point 4 above. What a consumer at a non-conforming GXP may be prepared to pay for one trading period does not mean that is the price/load combination they are prepared to be pay for multiple periods. The RTP proposal embeds rather than alleviates this situation.* 40. *To be able to make informed decisions greater visibility is required of the demand supply stack.* 41. *Implementation of RTP as proposed will require NZS to review Trading Period load and price bidding procedures. We are concerned the requirements to operate within the intent of the proposed RTP will impact the currently outsourced 24 hour energy load-bidding functions with increased costs potentially outweighing the CBA for NZS of improved unit price certainty.* *Workable options for non-conforming GXPs to vary load within one-hour gate closure are still being developed. We see this as essential to delivery of real-time pricing for all consumers.*

[28] Section 3.5.1, Transpower, Real Time Pricing Report (TAS060), February 2017.

Other comments	
NZX	***Publication of schedule information*** *Schedule 13.3B sets out the list of information to be published for each schedule by the system operator. Instead of fixing this list in the Code we suggest an alternative approach, whereby the list is managed by a service provider (either the system operator or WITS manager) and consulted on with industry. The consultation requirements would be similar to those for the clearing manager's prudential security methodologies.* *This alternative approach would have the following advantages:* • *The consultation process would encourage the list of published schedule information to more fully reflect participant's information needs. Access to information is a cornerstone of a well-functioning market, and;* • *Future changes in participant's information needs would be more easily implemented. Such changes may result from changes to market design, changes to market conditions or reducing technology costs allowing more efficient access to data.*
Orion	• *The possible interaction with existing and possible new demand side response needs further consideration.* • *It is unclear to us exactly when prices are to be produced under the proposal: whether they are a little ahead of a period or a little after the start of a period. In either case there is a question of whether the prices are actionable in the way that the paper conceives.* • *We are concerned that some forms of demand side response may lead to inefficient outcomes, and, in the extreme, to unstable outcomes which could be worse than no response at all.* • *There are important links to other Authority projects that need to be more fully considered.* ***High-level comments*** 4. *New and emerging technologies create new risks and opportunities for the wholesale electricity market and the power system more generally. There is a significant risk that the development of real time pricing in isolation of understanding the high level risks, challenges and opportunities associated with a new future will lead to sub-optimal outcomes and/or reputational damage for the industry. The risk of market and power system instability and the proposal around scarcity pricing and load curtailment (or threat of) are particularly concerning in this regard.* 5. *In our view the broader high-level problem definition should consider:* • *How will the market and power system need to change as customers with 'conforming/predictable' demand and energy profiles transition to customers with choice around when they consume, store or export energy?* • *How do we address uncertainty – what is the transition roadmap and how will risks be managed?*

Other comments	
	How does the future change the power system risk profile – more uncertainty leading to greater risk of failure - asymmetry – striving for efficiency (small gain) at the risk of failure (huge loss) *With enhanced demand side management capability how will we forecast medium term system security during peak demand?* *How will the market and power system make best use of supply and demand side resources both existing and new?* *How do we ensure that demand side response to the wholesale market does not overload the distribution network (from either load or export)?* *How do we ensure that demand side resources are allocated to the highest value proposition at the right time - wholesale market or delivery?* 6. *Exploring these problem definition questions and issues will help to provide clarity around next steps and the actions that industry participants need to take. There is potential for a rapid pace of change in technology and customer expectations associated with that. The electricity industry needs to move quickly but value should be placed on a low risk approach. There is much to be gained in the short term from implementing steps that achieve co-ordination and transparency of information and capability. In many cases, market capability can be overlaid later when back office system and functionality development catches up with customer expectations. A diagrammatic depiction of this is included as Appendix 1.* 7. *In terms of the real time pricing proposal, we observe the following:* *The potential for load and price oscillations and hence power system instability.* *Wholesale prices not reflecting competition created by demand side response.* *A lack of transparency around DSM capability and hence problematic system security planning – short and medium term.* *Peak winter wholesale prices dominating demand side response at the expense of driving power system delivery costs which are not reflected in real time.* 8. *A lower risk approach would consider:* *Transparency around demand side response capability – the same or similar to supply side* *Co-ordination of supply and demand side resources across the day, not just the next few minutes* *What needs to be done to ensure that the load forecast remains a reasonable prediction of base load* *How demand side response impacts on the distribution system can be efficiently managed*

Other comments	
	9. *We expand on some of these points below.* ***Comments on aspects of the paper*** 10. *As we see it there are three key ideas in the paper:* • *Spot prices should be more actionable and more efficient* • *Final prices should be based on the dispatch schedule* • *Where emergency load shedding is implied by the dispatch schedule then administrative "scarcity" prices should apply.* ***Prices should be more actionable and more efficient*** 11. *These are desirable attributes. However, we believe there is a trade-off between them that is not acknowledged in the paper. The closer to real time we get the smaller the set of available actions, even if the efficiency of any particular action increases. In the limit, the time frame is zero and no actions, efficient or otherwise, are possible. It is consumers, directly or indirectly, that respond to prices so their ability to respond and in what time frame needs to be top of mind when considering the trade-off.* 12. *All actions take time to implement, but some take longer than others, and so become less and less possible as we approach real time. The proposal limits the time available to the time between one set of dispatch prices being published, and the next. It is not clear on what basis this approach has been chosen as opposed to, for example, setting final prices based on information available 10 or 30 minutes before any particular period. It may be that implicitly the proposal seeks to minimise constrained on payments?* 13. *As we understand the proposal, forecast prices are still to be published and we see some risk that the present uncertainty around the relationship between forecast and final prices will simply shift to a different comparison. If forecast prices are supposed to be the, or at least a, reliable source of information for decision-makers, and if forecast prices are the most actionable prices but won't closely signal actual prices, there may be little overall improvement.* ***The price at other times*** 32. *We have fewer concerns about real-time price setting at other – non scarcity – times as this will generally be reflecting non-administrative bids and offers.* 33. *However, the concerns about the extreme short term nature of dispatch and how this interacts with the longer term (in this case primarily the rest of the day) forecast remain.* 34. *As well as the difficulties for the SO knowing quite what the demand it is looking at is made up of, there is the greater difficulty of knowing what will happen to that demand over subsequent periods. The quality of the SOs demand forecasting will be critical to success, and this will be more so the greater is the demand response. Much of the estimated*

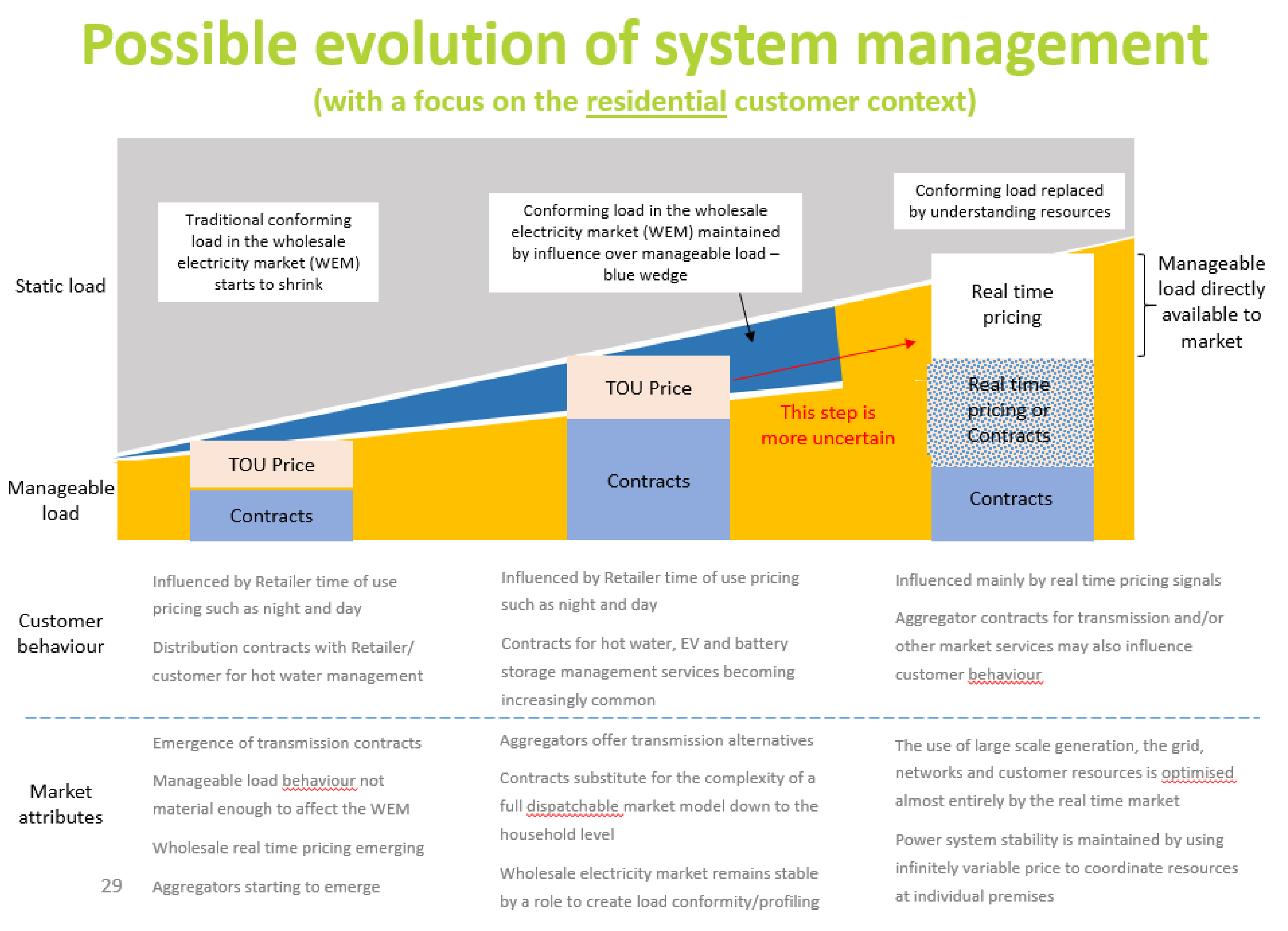
Other comments	
	benefits of the proposal arise from increased demand response, and we tend to agree this is more likely if the price is more certain. What is not clear is that this is actually a benefit when the impact on dispatch over time is taken into account. ***Interaction with distributor load management during some periods*** 35. *Distributor load management inevitably influences the wholesale energy market at certain times, since it changes demand – decreases it or increases it – compared with what it would otherwise have been. This affects dispatch and the proposal in a number of ways:* • *As already noted, load management is a potentially low cost source of demand response.* • *Load management may use resources, or make unavailable resources, that other parties may have bid or offered.* • *Load management may offset the effects of other resources. For example we are normally controlling to a load limit based on real time demand observations. If other demand response is occurring at the same time the system will automatically shed or restore load to keep aggregate load at the limit.* • *It will be important for the SO's forecast to accommodate this response.* 36. *As the number of parties participating in the market increases, be it directly or via third-parties such as load aggregators, there will be increasing interaction between the various parties and the associated resources. We believe coordination of these interactions will become more and more important as the number increases.* 38. *On 31 August the Authority published the following market commentary:*

Other comments	
	MORE ACCURATE PRICING CAN UNLOCK TECHNOLOGY POTENTIAL **It's important to improve the certainty and reliability of spot price information to enable the growth of new technology, such as batteries and electric vehicles, and business models.** For example, batteries can help to meet demand in peak periods, but need reliable spot price information to ensure they contribute energy at the most valuable times. It's likely that consumers will be less inclined to invest in and use batteries if they can't get reliable spot price information to help them make those decisions. Currently, spot market prices are finalised two or more days after 'real-time'—after generators have supplied electricity to the market and consumers have used the electricity. However, if prices were finalised in real-time, participants and consumers would receive more price certainty and could make better decisions about their electricity use. On 1 August we published a consultation paper on our real-time pricing proposal. If progressed, our proposal will be a major development for New Zealand's electricity market, and is the result of a detailed programme of work over many years. Our proposal would enable smarter decisions which are likely to save consumers money and reduce the overall investment that New Zealand needs to make in the power system. Prices would be more actionable and more efficient, and the process would be simpler and easier to understand. "More actionable" means consumers and participants can trust and respond to the prices they see in real-time. More efficient means consumers and participants would be much less likely to regret their decisions, and prices reflect the cost of resources actually used to run the power system at the time. Submissions on our consultation close at 5 pm on Tuesday, 26 September 2017. • *This commentary appears to prejudge matters currently subject to consultation. In our view this is not appropriate as it is at*

Other comments	
	odds with good consultation principles, for example as set out in the Authority's guidelines for distributors consulting on pricing changes:[29] *The [consulting party] must approach the matter with an open mind, and must be prepared to change or even start a process afresh.* *and* *Good practice includes: no pre-determination of any particular outcome, including being open to the possibility that, through the consultation process, any or all of the … change proposals may be abandoned or modified in response to feedback received.* ***Appendix 1***

[29] Electricity Authority, Guidelines for consulting on distributor tariff structure changes, 2 July 2012, p3.

Other comments



Other comments	
Powerco	• *We suggest the Authority further consider the operational implications of nodal scarcity pricing. There appears to be a mismatch between the resolution of wholesale settings and assumptions eg accurate meters at the node are not aligned with the resolution of transmission line ratings or demand-side dispatch options which will affect flows to/from nodes.* • *We suggest the Authority consider the linkages between nodal scarcity pricing and other pricing mechanisms and associated decisions. The signals for transmission constraints, transmission investment, load shedding, and demand response need to be aligned to maximise efficiency. Some worked examples may assist the Authority and stakeholders.* • *We want and need to understand the link between the pricing and dispatch implications of the proposal, especially around the price blocks for forecast demand. For example, the 5%/15%/80% price blocks appear to require a degree of quantity accuracy if they are called on. A common set of % bands across all GXPs (and EDBs) must reflect the reality of the GXP load, the ability to control it, and the ability to forecast it.* • *At the Wellington workshop, we suggested the Authority consider the implications of the proposal for each participant. The nature and scope of FAQ questions sent to the Authority reinforces the value of that exercise. It will ensure the EA and participants have a common understanding of the proposal and its implications.*
Transpower	*As stated in the report by the system operator, "the level of change is the greatest change to the market tools since their original deployment."*[2] *We note that the option chosen is the highest cost with a long implementation time; there will be an opportunity cost associated with the selected option over other less complex approaches. Transpower will be responsible for developing and implementing any approved change into market systems which will place heavy reliance on and demand for our specialist resources.* *While we will continue to support our normal operations, we may have limited ability to respond to any other proposals for material system change that might arise in parallel.* *We acknowledge that this consultation is not seeking views on whether to pursue 'option B' or an alternative option. However, we consider that the Authority should satisfy itself that the right balance has been struck between cost, complexity and benefits.* ***Discretion of system operator*** *The Code provides the system operator discretion to alter, or deviate from, the dispatch schedule to meet the dispatch objective (clause 13.57). Under real-time pricing, the dispatch schedule will be used to calculate settlement prices so any constraints imposed or altered by discretion would be included in the determination of settlement prices. As identified in the consultation paper, we expect no changes to current processes for real-time system operation.* *If the model produces prices that show scarcity values (indicating a supply shortage creating a supply / demand imbalance) then*

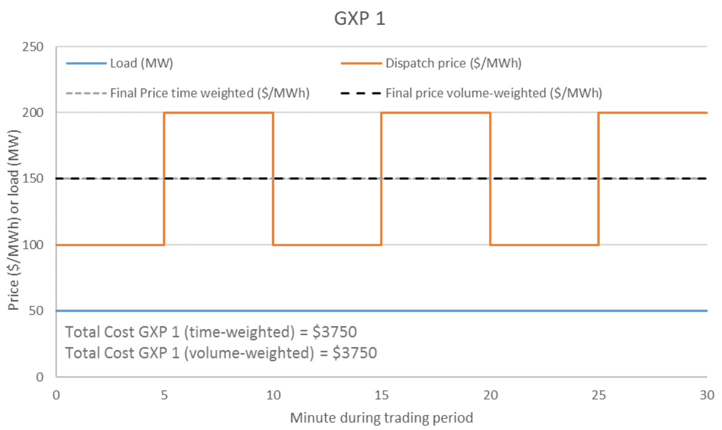
Other comments	
	the system operator can initiate demand management processes. The input to instigating demand management process for scarcity values in the dispatch is the same as for grid emergencies i.e. the physical state of the power system (frequency and voltage). The system operator will continue to account for any discrepancy between modelled and actual supply and demand imbalance. If demand management is instructed, then default scarcity pricing bids would be used in price formation. *As the implementation process unfolds the system operator can make available relevant operational processes to stakeholders for clarity on how discretion is applied. In addition, the system operator's policy statement*[30] *describes the dispatch policy and the means the system operator uses in real-time to meet the dispatch objective. We encourage participants to engage in the regular reviews of the policy statement to best inform the development of the dispatch policy under real-time pricing.*
Trustpower	• *We note that under RTP retailers will potentially be exposed to new price risks. In order to get a better understanding of these potential new risks, we submitted a number of questions into the Authority's Q&A process, including a request for worked examples of how RTP would work in a number of scenarios*[31]*. We thank the Authority for its detailed and considered responses to these questions. In our view the Authority's responses to these questions, along with other questions raised as part of the Q&A process, clarify the potential price risks that retailers may be exposed to under RTP.* • *Retailers will need to be able to mitigate these new potential pricing risks under the new arrangements. The clear identification of the potential risks during this consultation process will potentially help stimulate the development of appropriate new hedging arrangements which will provide one avenue for managing these new risks.* • *Based on the information provided by the Authority to date, including the worked examples, we also consider that there may be a reasonable case for incorporating pragmatic limitations on the risks faced by retailers into the design of the RTP arrangements. We support the Authority in further considering:* *a) Applying a limit on the price ratios that can arise during a spring washer event - explored further in our responses to questions 1 and 10 in Appendix 1; and* *b) Maintaining a cumulative price limit to apply during scarcity events - explored further to our response to question 8 in Appendix 1.*
WPI	*Access to actionable information: for WPI to be able to act on RTP, we would need easily assessable real-time information on the final price. We suggest that improving the accessibility of this information from WITS should be included in the RTP change*

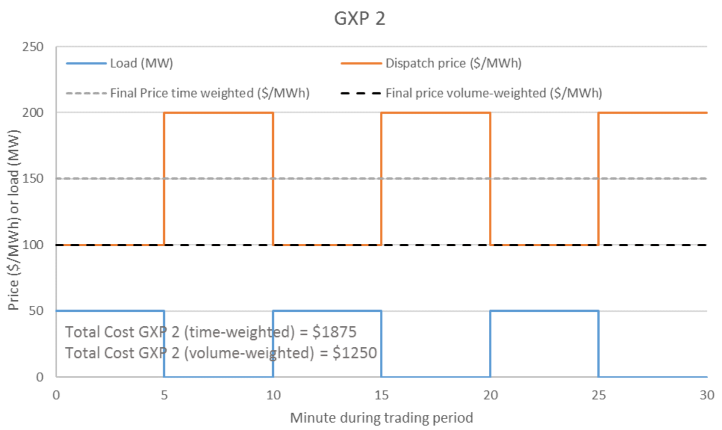
[30] For example, the recent consultation on the policy statement for 2017 is available here

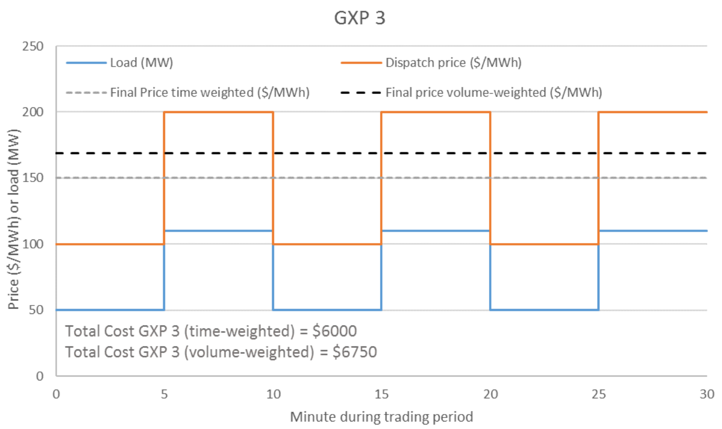
[31] Refer to: http://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/spot-market-settlement-on-real-time-pricing/development/real-time-pricing-frequently-asked-questions/

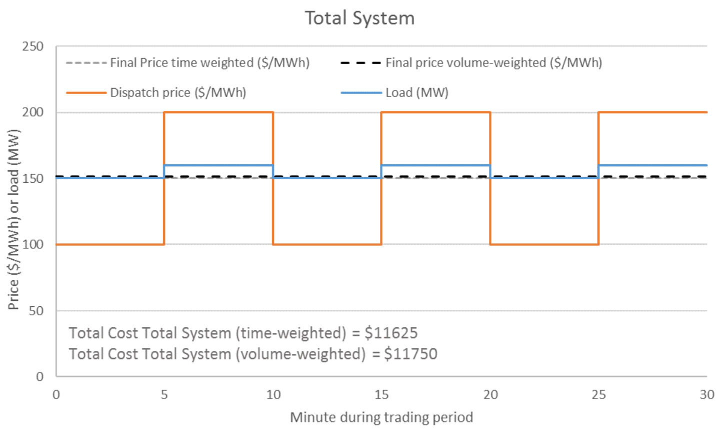
Other comments	
	project.

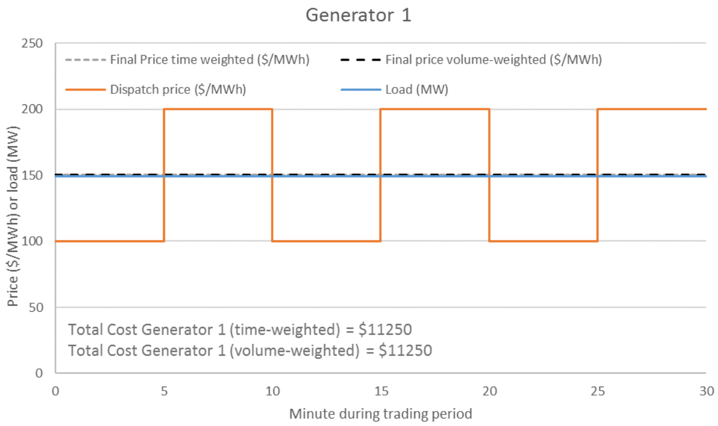
Charts included in EnerNOC's submission (response to Q2)

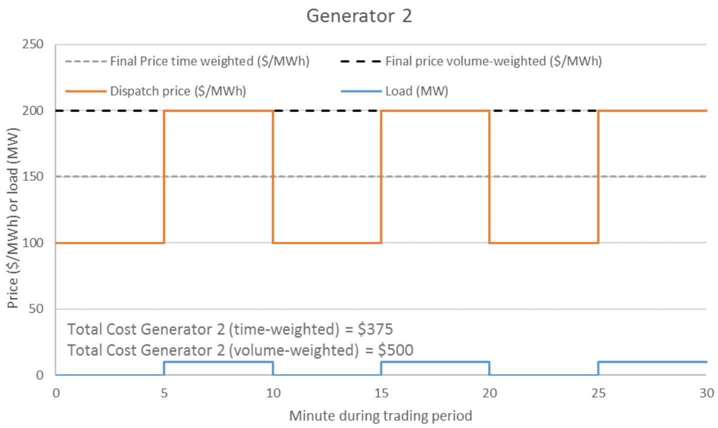









Generator 1
Final Price time weighted ($/MWh)
Final price volume-weighted ($/MWh)
Dispatch price ($/MWh)
Load (MW)
Price ($/MWh) or load (MW)
Total Cost Generator 1 (time-weighted) = $11250
Total Cost Generator 1 (volume-weighted) = $11250
Minute during trading period


Generator 2
Final Price time weighted ($/MWh)
Final price volume-weighted ($/MWh)
Dispatch price ($/MWh)
Load (MW)
Price ($/MWh) or load (MW)
Total Cost Generator 2 (time-weighted) = $375
Total Cost Generator 2 (volume-weighted) = $500
Minute during trading period

Appendices included in MEUG's submission

Appendix A: Initial assessment of DD-classic and D-lite to assist in further consideration of designing a D-lite option

Benefits and costs to customers participating in wholesale market	DD-classic	D-lite	Neither DD-classic of D-lite	
			Non-conforming node	Conforming node
Benefits				
~ Spot price certainty	Firm. Receive constrained on and off payments.[32]	At Purchasers option (whether comply with bid). Do not receive constrained on and off payments.	Less certain. Even with good demand side response capability will never get as firm price certainty as DD-classic of D-lite.	
~ Avoid load shedding if default scarcity prices apply[33]	Yes, if bid > default scarcity price.	Same as DD-classic.	Unlike DD-classic and D-lite, cannot avoid this risk when default scarcity prices reached.	
Costs				
~ DCLS approval	There Is an investment cost.	Same as DD-classic.[34]	No cost.	
~ Revenue metering	Required.	Non-revenue metering OK.	Not applicable.	
~ SCADA	Can be required in some cases.	Same as DD-classic,	Not applicable.	
~ Make bids	There is an operating cost. Must comply DSBF revision requirements for DD.	Same as DD-classic,	There is an operating cost. DSBF revision requirements slightly less onerous than DD-classic and D-lite.	Not required.
~ Comply with bids	Yes. Costs associated with non-compliance.	At Purchasers option. Limits on how frequently option can only be exercised. Operating and monitoring costs in deciding when to exercise option.	Not applicable.	
~ Using demand side response if not DD-classic or D-lite.	Not applicable.	Not applicable.	At purchasers option. costs of monitoring the market and deciding when to use demand side response. This can be complicated given less certainty of outcomes compared to DD-classic & D-lite.	

[32] Constrained on and off payments received for the applicable TP. Customer may be required to rebid and hence not benefit from constrained on and off payments in subsequent TP.

[33] Frequency of default scarcity prices applying is likely to be small and hence the probability weighted benefit is likely to be modest.

[34] Contact Energy asked if for certification as a DCLS for D-lite could be made less onerous that DD-classic. EA have responded this could be considered.

Appendix B: Key implementation details affecting customers in a RTP regime participating directly in the wholesale market

Topic	Notes
RTP design – in EA paper	
~ Mitigating yo-yo risks for DD.	Refer response to Q.13 in this submission.
~ Designing a D-lite product.	Refer response to Q.14 in this submission.
RTP design – new topics	
~ Need to review default scarcity values	Refer response to Q.4 in this submission.
~ Approval to be a DCLS	EA may consult further on whether current certification and audit requirements for full DD need also apply for "dispatch-lite".[35]
RTP draft Code amendments[36]	
~ cl.13.1	Is this clause relating to rebidding by DCLS within gate closure still needed? EA to reconsider during detailed design phase.
~ cl. 13.19A(3A)	A MW change made 1 TP before dispatch TP results in bid becoming a nominated non-dispatch bid. EA to consider revoking.
~ cl. 13.20	MW change 15" before TP requires DCLS purchaser that has made a nominated dispatch-bid, or a non-dispatch-capable load at a non-conforming load, to directly contact SO. EA to consider MEUG suggestions to automate.
~ cl. 13.19(A)(3B)	Current prohibition to switch between non-dispatch and dispatch 2 TP before dispatch TP. EA to reconsider for GEN events.
Complimentary to RTP[37]	
~ Enabling DD at conforming nodes	Refer response a) to Q.23 in this submission.
~ Make WITS data more actionable	Refer response b) to Q.23 in this submission.
~ Non-conforming node D forecasting	Refer response c) to Q.23 in this submission.
~ Existing DD pros and cons analysis	Refer response d) to Q.23 in this submission.

[35] EA response to Contact Energy.

[36] All these possible changes to the proposed code amendments were noted in the EA response to the MEUG draft memo of 4 September 2017.

[37] Not considered in this submission but mentioned in the EA FAQ's is the possibility of DD bids being subject to the trading conduct provisions.