10th October 2017

Submissions
Electricity Authority
Level 7, ASB Bank Tower
2 Hunter Street
Wellington

Via email:submissions@ea.govt.nz

**Submission on: Real-time pricing proposal – Consultation Paper**

Dear Sir or Madam:

EnerNOC welcomes the opportunity to comment on the Electricity Authority's (Authority) consultation paper 'Real-time pricing proposal'.

Our comments are based on our experience providing demand response capabilities in energy, capacity and ancillary services markets of various designs, and specifically in New Zealand where we have been offering customer load into the Instantaneous Reserves (IR) market since 2009. EnerNOC also provides forecasting for regional coincident peak demand (RCPD) and load bidding services for non-conforming nodes subject to the demand-side bidding and forecasting (DSFB) requirements.

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.

The above points are discussed in the following sections. An appendix has been included that provides comments on the formatted questions the Authority has included in the consultation paper.

## 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.

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.

## 2 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 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.

## 3 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.

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.

We would be happy to discuss these issues in more detail if that would be helpful.

Yours truly,

Michael Jefferson

Manager – New Zealand

## Appendix

The Authority has asked for feedback on a number of specific questions in the 'Real-time pricing proposal' consultation paper. The sections below addresses these questions noted in the paper. Some comments have been duplicated or developed further in the submission.

**Q1. Do you agree with the broad principle of using dispatch prices to determine final prices? If not, please explain your reasoning.**

Yes, more cost reflect the final prices are of actual system operation will improve the information available for parties to make informed decisions.

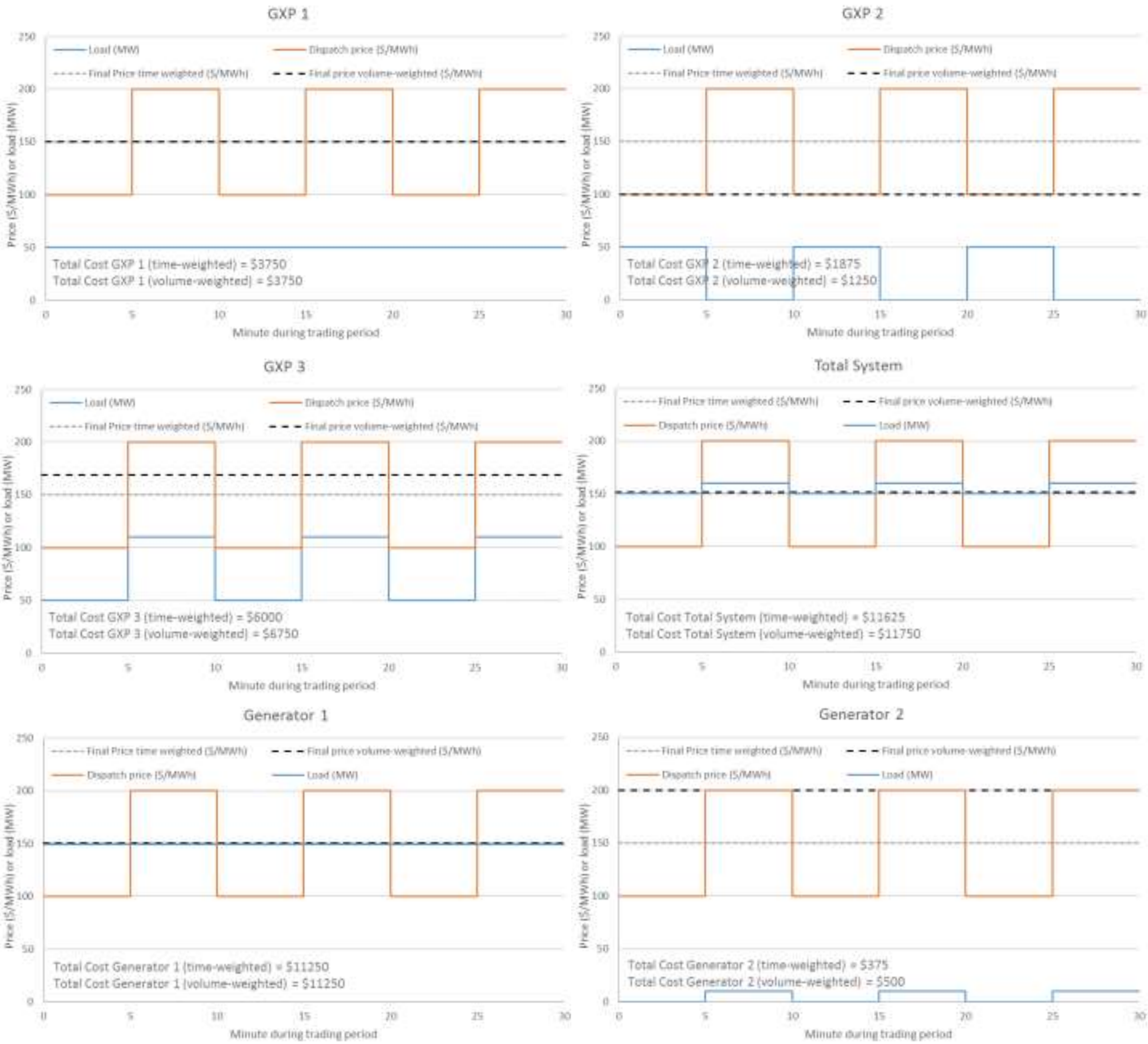
**Q2. Do you agree with using the timeweighted average of dispatch prices to calculate prices for a trading period? If not, please explain your reasoning.**

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.

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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.

**Q3. Do you agree with disestablishing the pricing manager and allocating residual functions to other parties? If not, please explain your reasoning.**

Yes

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

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

**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.**

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.

**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?**

Yes

**Q7. What is your view on the preferred treatment of disconnected nodes? Please explain your reasoning.**

Disconnected nodes should have their price determined by using the next most suitable node.

**Q8. Do you agree that it is not desirable to apply a cumulative price limit under RTP? If not, please explain your reasoning.**

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).

**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.**

Yes

This can be quantified by the following back of the envelope calculation:

$VOLL_{\text{load shedding}}$ = \$5,000/MWh

$VOLL_{AUFLS}$ = \$15,000/MWh

$Q_{\text{load shedding}}$ = 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:

$Cost_{\text{load shedding}} = VOLL_{\text{load shedding}} \times Q_{\text{load shedding}}$

$Cost_{\text{load shedding}}$ = \$5,000/MWh x 20MW / 2

$Cost_{\text{load shedding}}$ = \$25,000

Cost of reducing reserve procurement:

$Cost_{\text{reserve requirement reduction}} = VOLL_{AUFLS} \times Q_{AUFLS} \times P(UFE)$

$Cost_{\text{reserve requirement reduction}}$ = \$15,000/MWh x 870MW / 2 x 0.00017

$Cost_{\text{reserve requirement reduction}}$ = \$1,109

**Q10. Do you agree with the proposed removal of the high spring washer pricing provisions in the Code? If not, please explain your reasoning.**

Yes

**Q11. Do you agree with the proposed changes for demand inputs? If not, please explain your reasoning.**

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.

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

Yes, the best available data should be the primary data source followed by the next best etc.

**Q13. What is your view on the best approach to incorporate dispatchable demand within an RTP framework? Please explain your reasoning.**

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

**Q14. Do you agree with the proposed features for a dispatch-lite product? If not, please explain your reasoning.**

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.

**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.**

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.

**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.**

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.

**Q17. Do you agree we should retain a process for addressing material pricing errors? If not, please explain your reasoning.**

Yes, but the process must be transparent to all parties.

**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).**

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.

**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.**

The pricing manager (not necessarily the current pricing manager). This will insure the claims process to be undertaken impartially.

**Q20. Do you agree with the proposed treatment of spot prices during market system outages? If not, please explain your reasoning.**

Yes

**Q21. Do you agree with the proposed changes to forecast schedules to align them with dispatch schedules? If not, please explain your reasoning.**

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.

**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.**

Yes

**Q23. Do you agree with the proposed approach for transitioning to RTP? If not please explain your reasoning.**

Yes, however if delays are being caused by dispatch-lite it should be either removed or shifted into a secondary development work program.

**Q24. Do you agree with the objective of the proposed Code amendment? If not, please explain your reasoning.**

Yes

**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.**

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.

**Q26. Do you agree with our assessment of alternative RTP designs? If not, why not?**

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[i] 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.

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

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