MAJOR ELECTRICITY USERS' GROUP

29 April 2011

Lisa Du Fall
Electricity Authority
By email to submissions@ea.govt.nz

Dear Lisa

Consultation paper – Scarcity Pricing Options

1. This is a submission by the Major Electricity Users' Group (MEUG) on the Electricity Authority consultation paper "Scarcity Pricing – Proposed Design", 28th March 2011[1]. MEUG commissioned Sapere Research Group to independently consider the policy issues and alternative market based solutions. The Sapere report "An alternative to imposing a floor on spot prices during a public conservation campaign" April 2011 is attached and should be read as part of this submission.

2. References to the Sapere report are frequently made in this submission. To provide some context to those references, the last two paragraphs of the Executive Summary in the Sapere report follow:

   "The Authority has mistakenly focused on the supply-side in its consideration of how to improve system reliability and reduce the likelihood of a public conservation campaign. Improving the process of price formation, and the ability for consumers to see and respond to prices provides better alternatives that will provide greater long term benefit to consumers. We have demonstrated this by comparing a short-term forward market with the price floor proposal using a similar framework to the one the Authority used in the Compulsory Buy-back Arrangements consultation.

   The Authority should now take the time to develop a demand initiative alternative to comply with s.42e."

3. Several MEUG members have and will be making submissions on the consultation paper. MEUG members have been consulted in the preparation of this submission.

4. This submission and the Sapere report are not confidential.

[1] http://www.ea.govt.nz/our-work/consultations/priority-projects/scarcity-pricing-arrangements-proposed-design/

5. The consultation paper[2] describes the proposed changes to the market if the scarcity pricing proposals are implemented as "significant". MEUG believes this is an understatement of the fundamental change the proposals represent to market design. Such a significant change should only proceed if the benefits clearly exceed the benefits compared to other options. Our responses to the consultation paper questions that follow detail why MEUG believes the scarcity pricing proposals may be a response to a problem that may not be material. Even if there is a residual risk of spot price suppression there are likely to be better alternative market based solutions.

Question	MEUG response
Q1. To what extent is price suppression an issue with current pricing arrangements?	It is not a prime issue as explained in MEUG response to Q2 (price suppression risk in security of supply situations) and Q4 (price suppression risk in emergency load curtailment situations)
Q2. To what extent do you agree that the spot price suppression will adversely affect security of supply?	We agree with the Electricity Technical Advisory Group and Ministry of Economic Development preliminary report to the Ministerial Review of Electricity Market Performance of August 2009 that stated[3] "*At present there are incentives on some market participants to 'talk up' the risk a hydro shortage in dry years to persuade the media, government, the Electricity Commission and market participants of the need for a public conservation campaign. The effect of a conservation campaign is to lower spot prices, which reduces costs for market participants exposed to spot prices, but pushes the inconvenience and cost of demand reductions onto consumers*." This was the state of play up to 2009. The mix of policies agreed by Cabinet in December 2009, most of which have are in the process of being implemented, has removed both the incentives and ability for such lobbying and hence spot price suppression in the lead up to a potential energy supply shortage. The ability of spot exposed parties to persuade Ministers or regulators that a public conservation campaign (PCC) should be called in advance of when needed has been eliminated by the trigger for a PCC being hardwired into the Code and administered by the Electricity Authority independent of Ministers[4]. Furthermore the risk of future spot prices being too low

[2] Paragraph 162

[3] Electricity Technical Advisory Group and MED, A preliminary report to the Ministerial Review of Electricity Market Performance, Improving Electricity Market Performance, Volume one: Discussion paper, August 2009, paragraph 22, refer http://www.med.govt.nz/upload/69725/volume1.pdf

[4] Official conservation campaigns are commenced by the System Operator using a transparent deterministic methodology described in clause 9.23 of Subpart 4 Customer compensation schemes. Subpart 4 came into effect 1st April 2011 following gazetting of the Electricity Industry Participation (Customer Compensation Schemes) Code Amendment 2011, refer http://www.ea.govt.nz/act-code-regs/code-regs/code-changes/2011/#ccs. Prior to 1st April 2011 public conservation campaigns were arbitrarily triggered and prone to parties lobbying.

Question	MEUG response
	to underwrite infrequently used thermal dry year and peaking reserve plant has been reduced because: • The Government is proceeding to sell Whirinaki power station. As long as Whirinaki was offered in at administered and subsidised prices (ie capital costs recovered by a levy rather than having to be recovered through offers only like privately owned plan) then this inhibited private sector investment. The sale and purchase transfer date for Whirinaki is expected to be 1st December 2011; • The Government removing the ability of the regulator to acquire and have levy subsidised similar plant as Whirinaki in the future; • The Authority revising the Whirinaki offer strategy effective 1st March 2011 to prohibit offers below SRMC[5]. This overcomes the risk of the regulator offering below SRMC as occurred in Mid 2008[6]; and • Record offer prices set on 26th March 2011 that, should they stand following a decision on the UTS claims, more than cover stand-by costs for a year of even several years. Sapere in referring to offers on that day note[7] "*... this may further indicate that offer strategies are breaking out of the SRMC linked paradigm.*"
Q3. What is your assessment of historic security of supply performance, and the likely future performance under current arrangements?	No actual forced black-outs have occurred since the market started in 1996. There is no analysis that we are aware of that has examined if the high-priced events of 2001, 2003, 2006 and 2008 were near misses or a result of spot exposed participants "talking up" the risk to trigger demand reductions and thereby dampen the risk of even higher spot prices in the near future. While it is only a qualitative view, we think these events were significantly driven by parties "talking up" the risk. The ability of parties to lobby for earlier than need Public Conservation Campaigns has now been eliminated (refer response to Q.2 above). Three indices indicate security of supply from a reserves capacity and observed market behaviour point of view is

[5] Electricity Authority, Whirinaki offer strategy change, effective 1 March 2011, refer http://www.ea.govt.nz/industry/security-of-supply/reserve-energy-scheme/whirinaki-offer-strategy/

[6] In June 2008 the EC proposed and after consultation decided to offer Whirinaki below SRMC with the shortfall between actual generation costs and offer prices to be recovered by a levy. MEUG opposed the proposal by the EA, refer MEUG Submission on appropriation proposal for reserve energy, 2nd July 2008, http://www.meug.co.nz/includes/download.aspx?ID=96140

[7] Sapere report, footnote 9, p13

Question	MEUG response
	currently in good shape. First, the annual security of supply forecasts. The latest forecast by the System Operator[8] published in December 2010 reports no risks for the next few years. This begs the question as to whether there is a current security of supply margin risk. Second, observed investment in peaking plant recently part commissioned by Contact Energy at Stratford, being built by Trustpower at Marsden Point and signalled investment by Todd Energy in Taranaki. These investments would not have proceeded unless they were financially viable. Third, generator offer behaviour with the most recent being those observed on 26th March 2011 that "... are breaking out of the SRMC linked paradigm." (refer response to Q2. above that has a detailed discussion on the relevance of offers on 26th March)
Q4. What is your view of the proposed price floor to be applied in emergency load curtailment?	Paragraph 99 of the consultation paper states "*While decisions on the exact form of implementation have not been made at this stage, sufficient analysis has been undertaken to provide a high degree of confidence that there are workable options*." MEUG does not share the confidence of the Authority. There may be fixes to force a $10,000/MWh floor but we doubt they will lead to more efficient outcomes if better ways are found to signal market derived scarcity values in pre-dispatch schedules and for consumers to respond to those. In our view the consultation paper has a narrow focus on supply side alternatives for emergency load curtailment and has failed to investigate improved demand side response.
Q5. What is your view of the proposed treatment of load curtailment in AUFLS events?	The consultation paper consideration of AUFLS is superficial and we hope the Authority makes no decisions on AUFLS until the System Operator reports back on their broader Under Frequency Management investigation[9] that is reviewing Instantaneous Reserves, AUFLS and Asset Owner Performance Obligations. This is technically and from a market design perspective a complex issue and the System Operator bottom up and holistic approach is the most appropriate. The Under Frequency Management project work should not be constrained by decisions arising from this scarcity pricing consultation.

[8] System Operator, Annual Security Assessment 2011, January 2011, refer http://www.systemoperator.co.nz/f4571,43917808/ASA_2011_-_final.pdf

[9] System Operator Under Frequency Management Project, refer http://www.systemoperator.co.nz/ufm

Question	MEUG response
Q6. What is your view of the proposed approach to pricing during IR shortfalls?	We agree with the view in the consultation paper that changes to the IR market in mid 2010 have significantly and possibly eliminated any material IR shortfall price suppression risk[10]. The consultation paper gives no evidence that very high final pricing solution when IR shortage situations approach infeasibility is material. More analysis is needed to prove this or not. This is not an s.42 matter. We get the sense this idea was added into the rest of the scarcity pricing package as a convenience than having anything to do with the s.42 price new matter covering suppression risk and price floors.
Q7. What is your view of the proposed price floor to be applied in rolling outage load curtailment?	An inferior solution compared to: • Improved demand response capability using, for example, the day or week ahead forward market alternative examined by Sapere; and • A liquid hedge market to allow Participants through trades to derive a market price of future risks and for parties to act accordingly.
Q8. What is your view of the proposed disclosure mechanism?	Pointless and not supported. Paragraph 141 of the consultation paper declares the purpose of disclosure is to uncover those parties that have incentives to lobby for earlier than needed PCC. As we have shown in our response to Q.2 the ability for such parties to "talk up" risks has been eliminated by changes to market governance and Codifying when and who triggers a PCC that does not involve Ministers.
Q9. What is your view of these possible financial mechanisms?	These are draconian. Fortunately they should not be considered assuming the Authority agrees with our response to Q.8 above that disclosure mechanisms are now pointless.
Q10. What is your view of the comparative merits of disclosure versus a spot price floor to address concerns about over-reliance on public conservation campaigns? Is there merit in pursuing both mechanisms?	Neither is supported by MEUG.

[10] Paragraph 61 and 105

Question	MEUG response
Q11. What is your view of the proposed approach to imposing a minimum geographic threshold before any scarcity price floor is applied?	Not relevant as we do not support any floor pricing.
Q12. What is your view of the preferred approach to transition arrangements?	Not relevant as we do not support any floor pricing.
Q13. What is your view of the proposed approach to review arrangements?	The consultation paper proposes the Code specify reviews of the scarcity pricing floors every three years or after any event when floors were triggered. One of the reasons a review is needed is explained in paragraph 180, with underlined text emphasised by MEUG, "*Such reviews are important because although analysis and modelling techniques shed light on issues such as the appropriate level of scarcity price values, <u>there will necessarily be an element of judgement required</u>. For this reason, it is important to provide a review mechanism to incorporate new information and experience with a scarcity pricing regime*." Because judgement will be needed by the regulator at each review interested parties will lobby for exercise of that judgement to their favour. This creates uncertainty on the behaviour of the regulator and undermines robustness of the scarcity pricing regime over time. Investors in supply and demand side options to provide emergency services and mitigate the risk of energy shortage will defer decisions (perhaps in the hope of getting a better regulatory outcome) or add a risk margin for the regulatory uncertainty. This regulatory uncertainty has not been considered in the consultation paper cost benefit analysis. The need for a review illustrates the folly of the scarcity pricing proposals whereby the regulator by use of non-transparent models that require "an element of judgement" is supposed to have a better outcome than improving the ability of the market to price security risk as suggested in response to Q.7 above.
Q14. What is your view of the proposed changes when assessed against the Electricity Authority's statutory objective?	They fail compared to more market based alternatives.

Question	MEUG response
Q15. What, if any, other reasonably practicable options should be considered?	More market based alternatives as set out in the Sapere report.
Q16. What is your view of a capacity mechanism, when assessed against the Electricity Authority's statutory objective?	Capacity mechanisms have been considered in prior years and dismissed. We see no reason to change that view.
Q17. What is your view of the costs and benefits of the proposed changes?	At a very high level MEUG note the benefits are overstated because: • The starting point for the analysis of current security of supply margin is biased. The analysis assumes we are below the 780 MW of North Island Winter Capacity margin whereas in fact we are above that optimal point. Even if the balance of the analysis is correct and the margin will erode and fall below 780 MW, we still have several years' headroom. Therefore the benefits in the near term are overstated. • The benefits of scarcity pricing are static over the 20 years of the cost benefit analysis. The assessment of the static benefits is based on observed behaviour to date including historic rates of demand side response. Given improving demand side participation and improving hedge liquidity are both s.42 matters then a more plausible assumption would have been any need for regulatory interventions with floor pricing would have dissipated as those other policies come to fruition. Therefore the longer term benefits of scarcity pricing are overstated. Conversely the costs are understated because, amongst other things, the analysis fails to consider the regulatory risks associated with the proposed regular reviews as explained in response to Q.13. There is a more comprehensive discussion on the consultation paper cost benefit analysis in section 1.11 of the Sapere report. Section 1.11.2 of that report notes: *Taking all this into account, the $19 million net benefit indicated by the Authority seems very optimistic. This is equivalent to an average annual (undiscounted) net benefit of $2.2 million.* *This benefit is too close to zero to be*

Question	MEUG response
	meaningfully positive when you take into account all the unquantified costs listed and the possible costs associated with regulatory error. For example, the Authority has indicated that it estimates the net cost of setting the floor too high, causing excessive hydro spill, to be $2-3 million per year. Allowing for this cost, the price floor proposal is at best neutral. *While the Authority may argue that it will avoid this cost by setting the floors at the exactly optimal level it cannot avoid all the unquantified costs and it is not unreasonable to think that these will be in excess of $2.2 million a year.* *It should also be noted that the benefits (as given) may not be available as quickly as the Authority has assumed. Given the System Operator's assessment, we might suppose that no benefit is achieved until at least year 5, in which case the net present value is a cost of $1m*. After analysing the consultation paper cost benefit analysis of the scarcity pricing proposal, Sapere then consider an alternative being a day or week ahead forward market. The scarcity pricing proposals are inferior to the alternative day or week ahead forward market examined by Sapere in terms of an assessment against the Authority's statutory objective and an initial qualitative cost benefit analysis[11].
Q18. What is your view of the likely impact on prices of the proposed scarcity pricing changes, both in the near term (static effects) and over time (when parties can adjust their plans and behaviour)?	Relative to more market based approaches, with the scarcity pricing proposals prices will increase and this will affect production and investment decisions. Businesses would prefer to make production and investment decisions based on market set prices not prices set partly by market participants and partly the judgement of a regulator.
Q19. What further pro-competitive initiatives should the Authority be considering at this time?	More market based alternatives as set out in the Sapere report.
Q20. Do you agree that the undesirable trading situation provisions could be invoked to address an exceptional event, and	We will if necessary provide a response to this question after reviewing the Electricity Authority decision on UTS claims re 26th March offers.

[11] Refer sections 1.12.1 and 1.12.2 of the Sapere report respectively, pp 27-33

Question		MEUG response
	ensure that scarcity pricing is not applied in an inappropriate situation? If not, what changes should be considered in relation to the undesirable trading situation provisions?	
Q21.	What is your view of price capping mechanisms, when assessed against the Electricity Authority's statutory objective? Does your view alter if a mechanism such as a cumulative price threshold is applied on a transitional basis?	Price capping in any competitive sector of the economy brings the risk of unintended consequences and this also applies to the electricity sector. This is not to say price caps should never be applied; rather any application should have a very high burden of proof. As MEUG oppose any pricing floors then the option of mechanisms such as a cumulative price threshold is irrelevant.

6. In summary MEUG has concluded price suppression is a second order issue compared to the more important policy questions of finding ways to improve the ability of the market to price potential security of supply risks before shortages occur and during such events. Many policies introduced since decisions made in December 2009 are facilitating the market to rectify any mispricing due to poor policy settings prior to that date. But more is needed to improve demand side response and create true liquidity in the hedge market.

7. The scarcity pricing proposals in the consultation paper may have had some resonance prior to December 2009 but they are out of date now. In submissions to the Electricity Technical Advisory Group and MED in mid 2009 and the Electricity Commission in December 2009 MEUG had an open mind on what were then very high level conceptual discussions on scarcity pricing. We saw it as very much work-in-progress. The devil though is in the detail. This consultation paper is the first time in 18 months that we have had an opportunity to review progress. Given the material in the consultation paper and the report by Sapere that considers alternative market based solutions, MEUG believes it is clear the Authority should focus on alternative market focussed approaches rather than scarcity pricing to manage the risk of price suppression in emerging and actual energy security of supply situations or emergency load curtailment situations.

Yours sincerely

Ralph Matthes
Executive Director

sapere
research group

An alternative to imposing a floor on spot prices during a public conservation campaign

Vhari McWha and Toby Stevenson

April 2011

About Sapere Research Group Limited

Sapere Research Group is one of the largest expert consulting firms in Australasia and a leader in provision of independent economic, forensic accounting and public policy services. Sapere provides independent expert testimony, strategic advisory services, data analytics and other advice to Australasia's private sector corporate clients, major law firms, government agencies, and regulatory bodies.

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Executive Summary

Section 42 of the Electricity Industry Act 2010 requires the Electricity Authority *to impose a floor or floors on spot prices for electricity in the wholesale market during supply emergencies (including public conservation campaigns)* or to deliver to the Minister a report that explains *if, when and how the Authority proposes to provide for the matters.* Material contained in output from the Ministerial Review and Cabinet papers indicates that this provision is a response to the perception that generator/retailers rely on public conservation campaigns (PCCs) as a hedge against their fuel and generation decisions.

The issue of over-frequent lobbying for PCCs has been addressed for the most part by the adoption of a threshold as part of the compulsory buy-back arrangements. Retailers also face the estimated cost of voluntary load curtailment by households through these arrangements. These arrangements though address the symptoms rather than the underlying cause of the problem.

Fundamentally, the level of reliability provided by the market, and hence the frequency of PCCs is determined by the spot price of electricity. Spot prices should provide efficient signals during periods of shortage or conservation otherwise incentives for efficient investment in demand and supply side initiatives are disturbed and the reliability of the system is reduced. The underlying issue is that prices are formed ex post based on actual metered demand. So, during times of scarcity, prices are suppressed because demand is reduced, and the final price is based on that lower level of demand. Consumer preferences are not part of price formation.

Since the problem is the process of price formation during a period of leading up to and in anticipation of scarcity, the solution should improve the process of price formation and/or improve the ability of suppliers or consumers to see and respond to market prices. Efficient investment in generation and transmission capacity, efficient management of fuel and efficient demand response all depend upon efficient prices being formed in the first place, and then mechanisms being in place for market participants and consumers to see and react to those prices. Specifically:

- Consumers should be able to signal the price at which they would change their planned consumption for a sustained period.
- Those prices should be routinely visible to the market.
- Market participants should be able to respond to those prices.

- Retailers should have appropriate incentives to offer mechanisms that, in turn, give their consumers incentives to post prices indicating where they would cut load and an ability to respond to the resulting signals.

The Authority's suggested solution is to artificially raise the price when a PCC is triggered. Like the compulsory buy-back arrangements, this focuses on the symptom (the low price) rather than the cause (price formation). While this may reduce spot price suppression, it does not necessarily reflect consumer preferences and will not necessarily result in efficient pricing in the period prior to the scarcity situation.

It relies on the supply-side of the market to change their risk preferences and/or investment intentions to reduce the risk of a PCC. It ignores the demand-side, and the arguably greater flexibility it could offer given the diversity of consumers. It is surprising that the consultation paper dismisses demand-side initiatives as these are also a s.42 matter.

Such an intervention also sets an adverse precedent that the Authority is willing to set the price based on its view of generators' fuel management practices.

Given the statutory objective of the Authority, and in particular the emphasis placed on ensuring it acts for the long term benefit of consumers, it would be preferable to improve the design of the market to reduce or eliminate the problem of price suppression based on choices made by market participants that reflect their actual supply and demand preferences.

We have estimated that there is a significant amount of demand (possibly as much as 500MW) that would respond to a price signal if a mechanism was in place to exploit it. Most consumers can neither see nor respond to price at present.

Currently, up to the point of failure, prices are a function of generator offers, and these are mostly determined by the short run marginal cost of plant, or the opportunity cost of fuel. Where supply is constrained (in this case because of fuel shortage), prices should rise to the short-run marginal *opportunity cost* of supply. With constrained supply and no economic storage options, the opportunity cost of electricity is the price at which sufficient consumers would voluntarily reduce demand so that limited supplies are efficiently rationed.

The key is to change the process of price formation so that the demand curve is revealed and final prices take into account the price at which consumers are willing to reduce demand for a sustained period.

Creating the ability for consumers to see and respond to prices is critical to make the best use of their flexibility. If consumers were able to see the true cost of their electricity consumption then they have the choice to reduce demand during or prior to times of scarcity, invest in other energy sources or invest in energy efficiency measures instead. Given that it is not efficient for most consumers to continually monitor prices and change their behaviour, they need the ability to form price expectations and lock in their price and/or adjust their demand prior to real time. One way to do this would be with a short-term forward market i.e. a day ahead or week ahead market.

Day ahead markets are not uncommon internationally: Nordpool, a well functioning, energy only market, has one (and in fact has an hour ahead market as well). Such a market would:

- Be transparent.
- Expand the risk management options available.
- Encourage innovative retail products.
- Increase options for demand participation in the wholesale market, for example by aggregators.
- Better meet the Authority's statutory objective (promote competition, reliability and efficiency for the long term benefit of consumers).
- Contribute to other new matters under s.42.

The Authority has mistakenly focused on the supply-side in its consideration of how to improve system reliability and reduce the likelihood of a public conservation campaign. Improving the process of price formation, and the ability for consumers to see and respond to prices provides better alternatives that will provide greater long term benefit to consumers. We have demonstrated this by comparing a short-term forward market with the price floor proposal using a similar framework to the one the Authority used in the Compulsory Buy-back Arrangements consultation (see tables 1 and 2 below).

The Authority should now take the time to develop a demand initiative alternative to comply with s.42.

Table 1 Costs of a short term forward market relative to a price floor

Type	Frequency	Forward market	Price floor
Implementation cost – regulator	Initial	Some rule setting costs but relatively low since the mechanism is largely in place	Costs associated with setting the level of price floor, negotiating with SO over implementation details, code changes
Implementation cost – System Operator	Initial	Some set up costs – a day ahead market was part of the original market design, so it is not apparent that these would be particularly large, forecast prices are also currently prepared up to 36 hours ahead	Estimated by the Authority at $4.5m. The SO is required to make changes to the market clearing engine to implement the price floor
Set up cost – market participants	Initial	Some cost associated with making two offers/bids. Relatively low as offers and bids are already required up to 36 hours ahead	No system costs
Ongoing cost – regulator	Ongoing	Only if rule changes are required	Ongoing costs of monitoring, formal 3 yearly review, re-estimating floor levels
Operating cost – System Operator	Ongoing	System maintenance costs	Depends on the level of automation when price floors are imposed, if adjustments are manual this would impose higher ongoing costs on the SO
Operating cost – market participants	Ongoing	Some increase in costs due to requirement to make two bids/offers	Low, although some costs associated with risk management changes such as higher hedging
Higher prices during a shortage (transfer)	Ongoing	Transfer between market participants no net cost	Transfer between market participants no net cost
Allocative inefficiency associated with generators using localised market power during shortage or 'near miss'	Ongoing	N/a	Generators may alter their behaviour in order to trigger a floor (if they are long in generation) and/or set extreme prices during shortages

Type	Frequency	Forward market	Price floor
Setting price floor too high	Ongoing	N/a	Inefficient reduction in demand will occur. The Authority has estimated this cost at $1-3m per year, although this is probably conservative as the estimated reduction in shortage cost appears much too high. It is not clear how the shortage cost was derived given a high price floor results in storage in excess of an optimal level (so the chance of shortage is already low).
Implementation inefficiencies related to mechanism to set floor	Ongoing	N/a	Depends on the details of implementation (e.g. an offer floor may lead to unintended consequences for dispatch and hence security of supply concerns)
Lower retail competition due to lack of hedge products and higher prices	Ongoing	N/a	Retailers may choose to not enter/exit early due to costs associated with probability of floor being triggered and lack of available hedge/risk management products
Lower retail competition due to prudential requirements	Ongoing	Prudential requirements will rise but by less (possibly much less) than under the price floor	May see extreme increase if floor is triggered.
Higher spill and thermal fuel burn due to increased generator risk aversion	Ongoing	N/a	This proposal is intended to make hydro generators set a higher price for their storage. This may result in increased spill and higher overall system cost.
Regulatory uncertainty – modelling costs, credibility	Ongoing	N/a	Could be considerable. The Authority acknowledges the floor proposed for a rolling outage may not be implementable in practice; three yearly review means ongoing uncertainty; depending on the details of implementation hydro/thermal dynamic modelling may become difficult; sets an adverse precedent of the regulator setting the price based on its view of generator fuel management.

Table 2 Benefits of a short term forward market relative to a price floor

Type	Frequency	Forward market	Price floor
Higher wholesale prices for generators (transfer)	Ongoing	Transfer between market participants no net benefit	Transfer between market participants no net benefit
Lower frequency of foregone consumption due to voluntary, and instructed load shedding and rolling outages	Ongoing	At least as large as a price floor as level is set by revealed preference rather than administered estimate	Estimated by the Authority as $2.2m per year.
Reduced buyers' remorse due to lower than expected ex post prices	Ongoing	Buyers can see and 'lock in' prices ahead of time in all trading periods	Some benefit as prices will be above floor during some periods
Lower system cost	Ongoing	Less generation will be built as lower cost demand side alternatives will postpone investment	If price floor is set too high too much new generation will be built increasing system cost and potentially stranding assets
Lower hedge costs (search and transaction)	Ongoing	A regular, transparent mechanism for short term hedge cover will be available. This may assist the development of longer term contracts	This may exacerbate the reported problems of getting 'reasonable' terms and conditions for hedge cover as long generators will have increased opportunities to exercise transitory localised market power
Greater perceived security of supply	Ongoing	The intangible costs of disruption, and inconvenience will reduce as consumers can reveal their willingness-to-pay	Depending on the derivation of the price floors these avoided costs may be captured
New forms of participation	Ongoing	Traders and demand aggregators may enter the market, promoting competition	N/a
Contributing to other new matters under s.42	Initial	A forward market would contribute to s42(d) – demand side participation; and s42(g) – facilitating active trading of hedges	N/a

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Objective

Section 42(2)(b) of the Electricity Industry Act 2010 requires the Authority to *impose a floor or floors on spot prices for electricity in the wholesale market during supply emergencies (including public conservation campaigns)*. A "supply emergency" in this context means the possibility of a sustained shortage of electricity resulting from a fuel shortage (notably hydro) and possible complications resulting from transmission constraints.

When there is such a shortage, demand is curtailed until the shortage is alleviated. In the case of public conservation campaigns (PCC), there is a request for voluntary demand curtailment, ultimately though, if this does not occur, there is an outage (or rolling outages). A PCC is invoked by the System Operator and must commence when there is a risk of shortage in either the South Island only or the whole of New Zealand of 10% or more and that risk is forecast to remain for 1 week or more.[1]

The objective of s42(2)(b) is to artificially increase the spot price during an outage or PCC. Ordinarily the spot price is determined mathematically by matching actual metered demand with the supply stack. When demand is suppressed, whether through a forced outage or by voluntary curtailment in response to a PCC, the market does not clear. Nonetheless a price is calculated, based on the level of demand that is actually met.[2]

The essence of the argument presented by the Authority is that because prices are suppressed, there will be "inadequate provision of last resort generation and/or voluntary demand side response".[3]

Putting this another way, the probability of a supply shortage or PCC as determined by the market is too high (inefficient) as a result of the process for price formation during times of shortage. The objective of the proposal therefore is implicitly to *reduce the probability of a shortage or PCC* (as long as the cost of doing so is outweighed by the benefit).

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[1] Electricity Industry Participation Code clauses 9.23(1) and (2).

[2] Appendix A contains a more detailed discussion of price formation in the electricity market.

[3] Scarcity Pricing – Proposed Design, Consultation Paper s 4.2.1 para 78.

It is not the case that there should never be an electricity shortage; that would imply a very high level of redundancy in the system. The efficient level of reliability is where the marginal cost of further improvements is equal to the marginal benefit of higher reliability. The benefits of reliable electricity supply are the avoided costs of supply interruptions and quality degradation, and the avoided costs of under-investment by electricity users due to uncertainty. The costs of reliability are the resource costs associated with investing in and operating generation, transmission and distribution assets and the costs of demand-side response. The efficient level of reliability occurs when the sum of the avoided costs and the resource costs is minimised.[4]

Drivers of a shortage

Since the introduction of the electricity market in 1996 electricity supply in New Zealand has been marked by four major events of potential shortage, in 2001, 2003, 2006 and 2008. In none of those years was any forced curtailment of demand necessary, however, there were public conservation campaigns or calls for public compensation campaigns. The sense of crisis generated to support a conservation campaign is as damaging as the actual conservation campaigns themselves. This has undermined confidence in the market.

There have been concerns that public conservation campaigns have suppressed price signals during those years, which in turn means there has been insufficient incentive to invest in electricity peaking generation capacity.

One of the features of the existing market is that the flexibility of non run-of-river hydro means that hydro can play the role of both baseload and peaking plant depending on the opportunity cost of water at the time. As such New Zealand, in general, does not have a capacity problem, but rather an energy problem.

There have also been some short-term shortages at other times due to transmission outages (e.g. in Auckland); transmission capacity issues (upper South Island); and insufficient generation availability (19 June 2006).

Recent evidence suggests that the New Zealand market is pricing the risk of a hydro shortage more conservatively than previously. Prices levels observed in March 2010 and December 2010 suggest that even when storage levels were at historically

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[4] Refer to The Electricity Authority's *Interpretation of the Authority's Statutory Objective,* 14 February 2011.

expected levels hydro generators offer storage at high prices in order to protect their stocks.

In order to determine the most efficient (least cost) way of reducing the likelihood of a PCC we have considered the factors of market design that contribute to the probability of a supply shortage in four broad categories:

- The supply of fuel and management of the stock.
- Generation capacity installed and available.
- Transmission capacity installed and available.
- Demand responsiveness: the ability of consumers to see prices and react to them.

1.1 Fuel supply

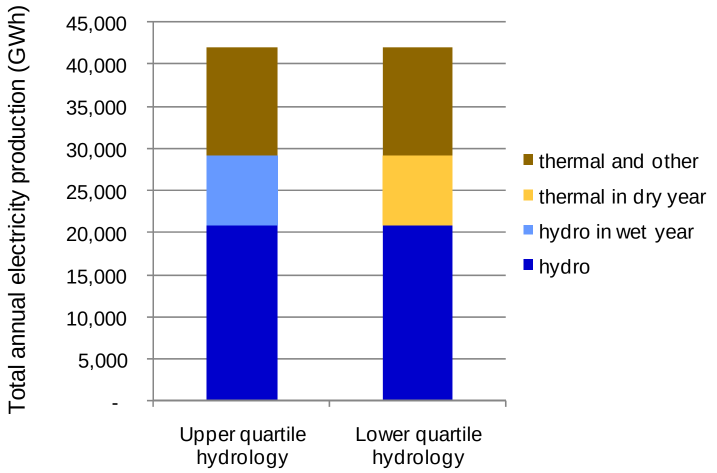
A change in the supply of fuel can have an immediate effect on the level of electricity that can be generated. A lack of gas due to a pipeline issue means that gas generators cannot operate, in the absence of a storage facility. Likewise intermittent generation is affected by the strength of the wind on a particular day. The market should be resilient to these types of adverse events which are similar in effect to an outage at a generation station for other reasons (e.g. plant maintenance).

In the context of security of supply the way the stock of fuel is managed can affect the probability of a shortage in future periods. Generators will endeavour to maximise their expected revenue and in doing so they will take a view on the present value of fuel stocks compared to the expected future value. Some of the factors involved are externally driven, such as the probability of more fuel becoming available (i.e. rain).Others are decisions made by the generator in the context of the market design and rules, such as spot price expectations, the level of hedging the generator has in place, the size of their retail base and in the case of coal generators decisions around the timing of fuel delivery. These decisions could potentially be influenced by design changes.

As is well known hydro inflows are variable and storage is limited in New Zealand. These factors, combined with limited alternative capacity, mean that hydro shortages are always possible. There have been some issues in the past with coal supplies to Huntly and some uncertainty over future gas supplies, however, these issues are of limited effect when compared with hydro.

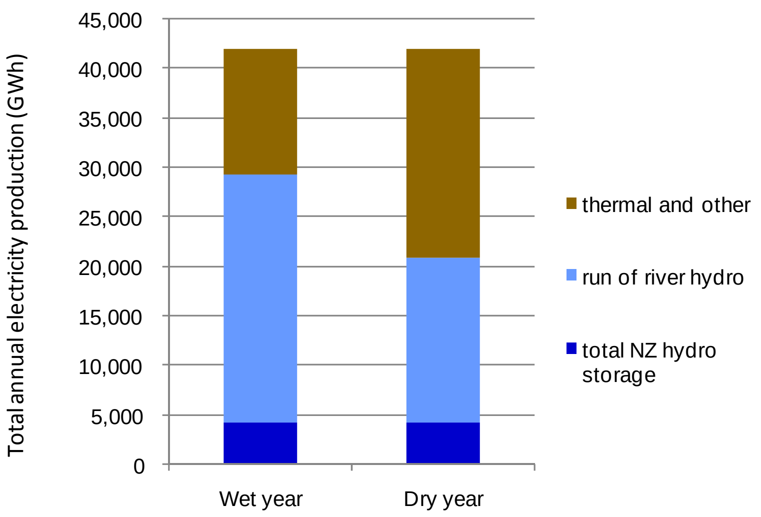
To illustrate the hydro variability problem the figure below shows the difference in contribution from hydro generation in a 25 percentile year and a 75 percentile inflow year. There is a 8500GWh difference in thermal generation in wet and dry years.

Figure 1 Thermal generation in wet and dry years



The hydro variability problem is exacerbated by the level of hydro storage in New Zealand. Figure 2 plots total New Zealand storage capacity over total demand. There is a total storage capacity in the system of approximately 4000 GWh or 10% of total demand. So a swing of 8000 – 9000 GWh per annum between a dry year and a wet year puts the emphasis on standby generation being maintained and available and accompanying fuel being available for the dry years.

Figure 2 Hydro storage as a proportion of generation



1.2 Generation capacity

The level of generation capacity clearly affects the likelihood that there will be a shortage in supply. The more spare capacity that exists relative to the system peak the less likely it is that an outage will occur. Generators generally derive their revenue from hedge market, spot market or reserves market trades. New capacity will only be installed if the generator believes that the revenue available will exceed their costs. Decisions around the installation of new generating capacity are fundamentally driven by market design.

In general, generation capacity is not a problem in New Zealand at the half hour level. The amount of generating capacity easily exceeds New Zealand peak demand. Capacity only becomes an issue when too many generating units are down for maintenance or are not available to ramp up, hydro storage has run out (which has not yet happened), or transmission constraints prevent electricity from getting from one place to another. There have been some occasions when one of the island reserve markets has had to be suspended but this has not happened to our knowledge because of any fundamental flaw in the generation fleet composition; rather it is due to short term disruptions (transmission or generation outages) or participant choices regarding plant commitment.

1.3 Transmission capacity

The level of transmission capacity also affects the likelihood of an outage. If there is insufficient transmission capacity then generation capacity can be available, but not where demand is because there is no way of transporting the electricity.

There are several issues raised by the physical features of New Zealand's transmission grid. The main one of these is the HVDC link between the North and South Islands. Price separation between the two islands is a frequent outcome in final pricing because the HVDC often sets the reserve risk. The replacement of pole one with pole three should see this constraint ease, which will increase flows between the two islands, assisting with energy security.

Having to maintain sufficient reserves in both islands is another reason that, in general, there is sufficient capacity in New Zealand, as each island must have sufficient generation to meet its own supply and reserve.

1.4 Demand response

The final factor that affects the probability of a shortage relates to the ability of users to see prices and then react to them. Demand response can be a short-term response to price spikes (peak lopping) or a longer-term response to fuel scarcity or capacity shortage (energy conservation). The latter is more relevant in the context of security of supply, suppressed prices and public conservation campaigns. Instantaneous response is less important than making the price at which consumers are prepared to reduce demand for a period visible and ensuring mechanisms that give them an incentive and opportunity to do so are available.

The issue takes different forms depending on the size of the consumer and the nature of their supply arrangements. We distinguish between:

- The largestindustrial users exposed to wholesale prices. They may hedge all of part of their load with fixed price fixed volume financial contracts. They monitor spot prices or may have agents who monitor prices for them.
- Commercial consumers with time of use meters. These consumers tend to have fixed price variable volume contracts. Some may have part fixed price and part spot exposure. Where these consumers have spot exposure this would tend to be delivered through a retailer, who generally monitors spot prices on their behalf.
- Mass market consumers are typically on fixed price variable volume tariffs. There will be a discount for mass market consumers who agree to having some of their load – usually hot water cylinders – remotely switched on and off for the purpose of shifting load from one time of day to another. That arrangement tends to be managed by distributors and the load shifted for the purpose of reducing distribution and transmission costs in the system. In some cases a retailer may control the load.

Currently there is a transformation underway whereby cumulative meters are being progressively replaced with time of use meters. These would enable a greater diversity of tariffs, load control over a wider range of appliances and more easy communication about the imperative to manage load.

Summary of market design

Table 1 sets out the existing features of the New Zealand electricity market grouped by the four factors we have considered as possible drivers of a shortage. More detail on the current initiatives is available in Appendix B.

Table 3 NZ market design features relevant to the probability of a supply shortage

Fuel supply	Generation capacity	Transmission capacity	Demand response
Hydro dominated (approx 60% of generation), storage geographically clustered and limited (***10%*** of national annual demand)	No price cap, negative prices possible	Investment regulated by Commerce Commission	Flat, fixed rate tariffs for most residential consumers (although possible to change with short notice)
PCC triggered at 10% probability of shortage, ends at 8% probability	Energy only market	Use VoLL of $23,185/MWh ($20k in 2005 prices), but prices do not reach this level in real time	Unregulated retail competition
Immature hedge market implies reliance on vertical integration to manage revenue volatility associate with fuel uncertainty	Full nodal pricing	Long stringy grid – relatively high losses, lack of alternative routes	Mass market demand response mostly in the form of ripple control, some fixed time control. Otherwise relies on response to changes in bundled delivered charges.
Bids are not used in dispatch, so the value of non-supply is not captured (also relates to capacity)	Co-optimises energy and reserves	N-1 reliability standard for core grid, economic/probability for other assets	Many large consumers have time of use metering which enables prices that differentiate between time periods
Emissions charge makes gas more attractive than coal but gas has low certainty from a generation investment perspective	Block dispatch	Two islands connected by (old/low capacity) HVDC	Indicative prices are forecast every 2 hours up to 36 hours ahead

Storage has been dominated by single owner, no longer true due to asset swaps	Details of (all?) hedge contracts must be disclosed	Remote location means cannot import electricity (or most types of fuel?)	Distributed generation encouraged
Must run generation can potentially exceed total demand overnight	EA has contracted Crown to provide reserve energy (called 'generation capacity') from Whirinaki PS	Generation is distant from demand centres, which are main cities and remote large industrial plant (e.g. Rio, CHH, Glenbrook, Fonterra, Refinery)	Residential consumers qualify for a payment during shortage events
Vulnerable to Maui pipeline/field failure (NB Crown took risk for e3P)	Vertically integrated generator/retailers dominate the supply side of the market	High loss system	Water heating, space heating and lighting comprise more than half of residential use
Lack of gas storage (changing)	Cannot import electricity	Common carriage (no capacity rights)	Summer demand increasing
Seasonal inflows highly variable so shortages tend to be whole of season i.e. potentially lasting through to spring.	High fixed cost, uncertain return on spot		Consumers take what they want with no retailer veto, because demand is weather driven it is unpredictable and variable
Wind investment relatively high despite cost and intermittent nature	Same generation capacity can be offered as both energy and instantaneous reserves in the same trading period		
Resource consent constraints on eg hydro min/max levels/flows, max rate of change, Waikato river temperature, geothermal max draw off rate, standby generator time of day	Resource Management Act		
	Peakiness of demand – daily/weekly/annually – residential use determines daily pattern		
	Generators and HVDC owner pay IR costs through availability cost unless under-frequency event, where causer pays event charge suggests reluctant to offer vulnerable assets (eg HVDC) or set high price		

Table 4 Current initiatives relevant to security of supply

Fuel supply	Generation capacity	Transmission capacity	Demand response
Security of supply monitoring improvements (now undertaken by Transpower as System Operator)	Monitoring and supporting industry progress to a liquid hedge market	Implement a mechanism to allow locational price risk management	Demand side bidding and forecasting
	Investigation into the value of unserved energy	Transmission pricing methodology	Review of property rights for load management
	Review of the Whirinaki reserve energy offer strategy	Grid support contract	Dispatchable demand regime
	A sale process for Whirinaki is underway	Recent RMA changes have also assisted transmission investment	Review of the Code relating to metering
	Instantaneous reserve dispatch		
	Customer buy back		
	Recent RMA reforms and new National Policy Statement for Renewable Electricity Generation 2011		

Table 5 Other possible measures relevant to security of supply

Fuel supply	Generation capacity	Transmission capacity	Demand response
	Capacity market		Day ahead or week ahead market
	VoLL price		Small consumer pricing contract based on dry year/normal year
	Well-functioning hedge market		Ex ante pricing
	Amendments to gross pool		Five minute settlement

A mechanism to reduce the risk of shortage

We have identified four factors that affect the probability of a supply shortage or PCC:

- The supply and management of fuel
- Generation capacity
- Transmission capacity
- Demand responsiveness

Fundamentally, the level of reliability provided by the market is determined by the price of electricity. Spot prices should provide efficient signals during periods of shortage or conservation otherwise incentives for efficient investment in demand and supply side initiatives are undermined and the reliability of the system is reduced. Efficient investment in generation and transmission capacity, the management of fuel and demand response all depend upon efficient prices being formed and mechanisms being in place for market participants and consumers to see and react to those prices.

Since the problem is that the process of price formation delivers a price that is too low during times of shortage or near shortage, the solution should improve the process of price formation, and/or improve the ability of suppliers or consumers to see and respond to market prices. This will have an effect on one or more of the factors listed by providing more efficient signals. Specifically:

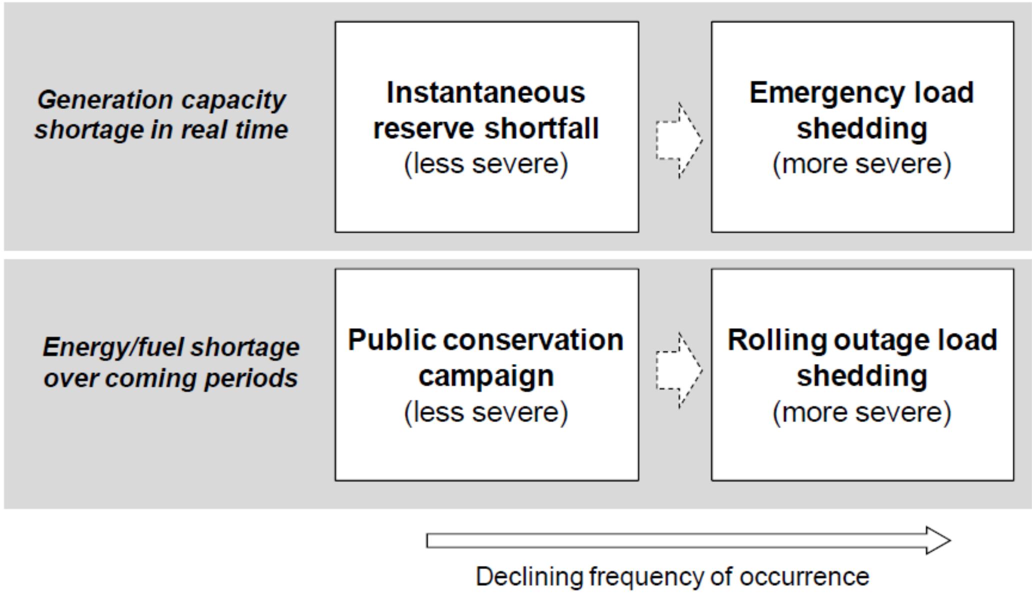
- Consumers should be able to signal the price at which they would change their planned consumption for a sustained period.
- Those prices should be routinely visible to the market.
- Market participants should be able to respond to those prices.
- Retailers should have appropriate incentives to offer mechanisms that, in turn, give their consumers incentives to post prices indicating where they would cut load and an ability to respond to the resulting signals.

1.5 The Authority's price floor proposal

The Authority has identified four situations where price suppression is considered to be a problem and illustrated them in the following diagram.[5]

[5] Consultation paper, para 46.

Figure 3 Supply emergencies and non-price responses



The Authority has promulgated a solution to the problem of price suppression during periods of excess demand that artificially raises the price to a level chosen by the Authority. This puts the onus onto the supply side (i.e. generator/retailers), appealing to the generation and risk side of their businesses. This ignores half the market, which arguably has greater flexibility given the diversity of consumers. It does not do a good job of meeting the criteria suggested above for a solution.

The Authority considers its pricing floor initiatives will *alter the way that spot prices are determined in a supply emergency to reduce the risk of spot price suppression and/or improve regulatory certainty*.[6] While spot price suppression may be reduced, it is not the case that the level of prices will necessarily reflect consumer preferences.[7] Prices should be visible to consumers at all times and mechanisms should be available for participants to respond to price signals should they so wish. The analysis provided by the Authority appears to dismiss that possibility asserting that although *the level of demand-side*

[6] Consultation paper, para 91.

[7]And it is not at all clear that regulatory certainty will be improved as an administered price requires monitoring and review, and potential revision by its nature. In addition, it is not clear whether the threat of administered prices is credible. Finally, there is the threat of regulatory creep if the Authority identifies other situations where it does not like the market price – this creates an adverse precedent for price setting.

participation is likely to grow over time, the inability of most users to directly signal their preferences in supply emergencies is expected to remain for some time. This means that the potential for price suppression will continue.[8]

1.6 Enabling demand response

Clearly, it would be preferable to improve the design of the market in such a way that the price suppression problem is reduced or eliminated based on choices made by market participants that reflect their actual supply and demand preferences. At the moment, prices are constrained by social and political expectations that they should not go above short-run marginal cost (SRMC)[9]. The demand curve is never revealed and the value consumers place on electricity is largely unknown.

It is well established in public utility economics that peak load pricing is optimal in an electricity market. "To maximize the social surplus, prices during the off peak period should be set equal to the marginal cost of energy and prices during the peak period should be set equal to the marginal cost of energy and capacity."[10] Where supply is constrained (in this case because of fuel shortage), prices should rise to the short-run marginal *opportunity cost* of supply – with constrained supply and no economic storage options, the opportunity cost of electricity is the price at which sufficient consumers would voluntarily take their next best alternative rather than consume an extra unit so that limited supplies are efficiently rationed.

If consumers were able to see the true cost of their electricity consumption then they may choose to reduce demand at peak times, invest in other energy sources or invest in energy efficiency measures instead.

Another option for meeting an additional MWh of demand would be to allow consumers to trade in order to facilitate the highest value use being satisfied. It is welfare enhancing to allow consumers to trade if they place different values on consumption at the margin.

[8] Consultation paper, para 90.

[9] Since March 1 2010 Whirinaki has been offered at a stand by price of $5000/MWh. This has resulted in other generators offering plant in at $5000/MWh although these offer prices have not generally resulted in cleared prices yet. The Whirinaki stand by offer price is under review by the Authority at present. However, provisional prices for March 26 2011 have prices set on the basis of a $20,000/MWh offer price at 51 nodes for 14 trading periods in the Auckland region. That event is under consideration by the Authority. Regardless of the outcome of that investigation this may further indicate that offer strategies are breaking out of the SRMC linked paradigm.

[10] Faruqui, Ahmed and Sanem Sergici *Household response to dynamic pricing of electricity – a survey of the experimental evidence*, 10 January 2009.

This is achieved by demand side participation in the wholesale market. A consumer with a fixed volume contract can offer to reduce load by 1 MWh and is paid for that electricity at the wholesale market price by another consumer who values the load more highly.

It seems likely that the variability of values placed on electricity use by consumers will lead to a lower cost outcome than relying purely on supply-side solutions.[11]

The consultation paper observes that *discretionary demand reductions are a valuable source of flexibility to address dry year risk* but goes on to dismiss it as part of the solution. *Aside from demand cuts by industrial and commercial users exposed to spot prices, there has been little evidence of active demand response initiatives. Indeed, for residential and commercial customers, the provision of incentive-based arrangements appears to have lessened over time.*[12] This ignores the fact that the Electricity Commission was given responsibility for security of supply in 2004, and generators and retailers changed their behaviour in response to its decisions.

The consultation paper correctly observes that *ideally, the concerns about price suppression noted earlier would be addressed by ensuring that electricity users could directly participate in spot price determination – as typically occurs in markets for other products. The resulting market price should better reflect users' preferences about the value of continued supply, and eliminate the risk of price suppression (or overshooting). It should also ensure that available supply is allocated to those parties who place the highest value on continued usage.*[13] But the Authority does not pursue this solution.

1.7 Availability of demand response

In theory all load in New Zealand could be on electricity supply contracts that signal the costs of energy during hydro shortages. In practice most customers do not face the high spot prices that occur periodically and instead incur a risk premium in their current tariffs which allows retailers to recover their costs.

[11] We know that different consumers place different values on electricity consumption from observed behaviour – some demand is offered as instantaneous reserve, some curtailment occurs during PCCs, surveyed measures of the value of unserved energy indicate that even in aggregate industrial, commercial and residential users place different values on uninterrupted supply.

[12] Consultation paper, para 86.

[13] Consultation paper, para 89.

For the most part, demand response takes place in timeframes that are greater than a year. However, hydro shortages become manifest in much shorter intervals that are expressed in weeks and months.

The following table looks at the different time frames and physical measures that can be taken to show demand response:

Table 6 Energy demand response by category of consumer

	Industrial	Commercial	Retail
Immediate	Interruptible load offers made directly Response to five minute prices	Interruptible load offered by another party on their behalf Limited response to five minute prices	Interruptible load offered by another party on their behalf
Day ahead	Bids submitted to WITS provide some transparency to aid in decisions to curtail based on forecast prices	Limited	None
Monthly	Build up inventory Reschedule production Stop production temporarily	Limited response based on tariffs that vary by month	Limited response based on tariffs that vary by month
Yearly	Take operations overseas Close down permanently Build own generation Build co-generation Invest in energy management or saving tools	Switch to gas Investment in energy conservation measures	Switch to gas Purchase more efficient appliances Insulate home

The list is not exhaustive. Some demand response transfers consumption into another trading period, such as interruptible load. This is useful for pure capacity shortages but not when there is any energy shortage (such as during a PCC). The main point to make is that all categories of load do make demand responses, however, most of those responses are not based on price signals from the half hour spot market.

Furthermore, those parties that can respond immediately face the uncertainty of not knowing what the final pricing outcome will be until later. This provides an incentive to avoid exposure to the spot market.

1.7.1 Barriers to timely demand response

Some of the barriers to demand side participation are preference: consumers prefer to know what their tariffs are in advance and do not like the idea of facing the risk of high prices for short periods, even if, on average, the total cost of electricity provision over a year might well decrease.

Another reason for limited participation is that there are few retailers that offer any type of variable price contracts. This situation is changing, however, with the emergence of smaller retailers that are willing to innovate with tariffs that do vary by month, or even with some limited spot price exposure.

There are also some technical barriers. Most consumers do not have electricity meters that facilitate effective demand response contracts. As already noted, this situation is changing.

1.7.2 Estimating the amount of possible demand response

The table provides an indication of the amount of demand response that could be available in New Zealand now if the financial incentives existed to exploit it. The numbers are a combination of estimates and averages[14]. More analysis would be needed to verify the exact amount of load on TOU meters and the willingness of consumers to reduce load. It is understood that close to half of all load is currently treated as half hour load in the reconciliation process. However, there is also some load that, though it is measured with time-of-use meters, is not yet being submitted as such because systems are not yet in place to deal with it.

However, past savings campaigns do give an indication of possible savings that can be made. During previous conservation campaigns demand reduced by between 7.6% and 9.5% (excluding major users, who are less likely to be on variable volume contracts). That suggests that there is variability in demand that could be captured if the mass market consumers could see the price signal (and be rewarded for reacting to it). Interruptible load forms about one third (200MW) of instantaneous reserves.

In theory, there is no limit to the amount of load that might be curtailed at the right price. At some point it will be cheaper for a business to cease production and for a domestic

[14] Current estimates of half hour meters available to retail and commercial customers are derived from a Concept Consulting report to the Parliamentary Commissioner for the Environment in June 2008 – *Smart Metering in New Zealand*. Estimates of future installation plans are derived from websites of retailers and distributors with plans to install smart meters. Current average load figures are taken from the MED website with an assumption of 2% annual growth made.

consumer to buy a diesel generator. However, the numbers we have put in for sustainable curtailment can be assumed to take place at prices of less than $5,000/MWh.

Table 7 Possible energy demand response by category of consumer 2011

	Industrial[15]	Commercial	Retail	Total
% of load	41%	25%	34%	100%
Average half hour load	1800MW	1100MW	1500MW	4400MW
Load on TOU meters	95%	80%	12%	62%
Percentage of load that can be sustainably curtailed	25%	7.5%	7.5%	11.2%
Load available for demand response	415MW	65MW	13MW	493MW

These numbers are evolving, with a number of retailers rolling out time-of-use meters. By 2015 it is expected that at least 80% of retail consumers will have a smart meter installed.[16] This suggests that the situation in 2015 could look something like this:

Table 8 Possible energy demand response by category of consumer 2015

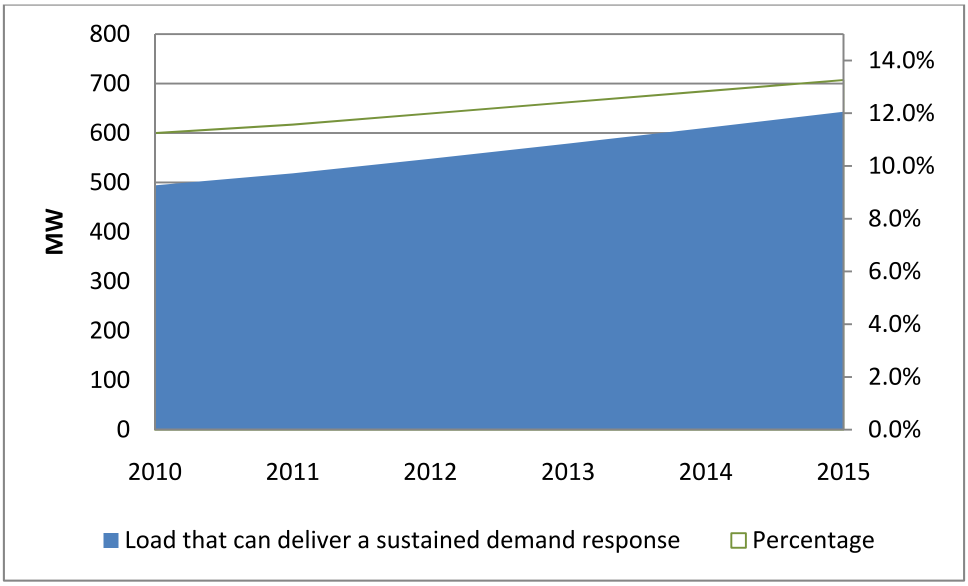
	Industrial	Commercial	Retail	Total
% of load	41%	25%	34%	100%
Average half hour load	2000MW	1200MW	1700MW	4900MW
Load on TOU meters	100%	90%	80%	85%
Percentage of load that can be sustainably curtailed	25%	7.5%	7.5%	13.3%
Load available for demand response	500MW	80MW	100MW	680MW

[15] Includes agriculture

[16] Based on media releases

Graphically, the situation looks like this:

Figure 4 Projected load available for sustained demand response



Technically therefore there are few barriers to prevent a sizeable demand response even now that would achieve the objectives that the Authority is seeking. Even if these numbers were over-estimated by a factor of two, there is still the equivalent of one of the Huntly units available in demand response[17]. The question is how to facilitate that response in an efficient way.

1.8 Improving market design

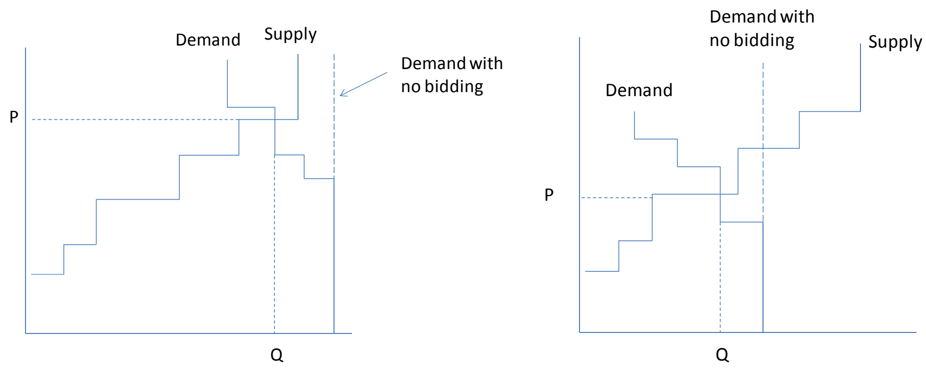
The problem is that prices are malformed based only on the SRMC of generation: higher prices are considered unjustifiable, despite the well-worn theoretical explanation set out above. The demand curve is not revealed, so the value that consumers place on electricity is unknown. Prices do not provide efficient incentives to either suppliers or consumers. In fact, most consumers can neither see nor respond to price.

[17] Note that we have used average load figures. The savings percentages achieved in previous years were during the colder months when load was much higher than the average. We have also not attempted to build in any price sensitivity, merely to outline how much load we think might be available for demand response at previously observed prices and levels of curtailment.

In a market-determined solution, when lake levels decline (i.e. the probability of shortage rises) prices would spike, demand would decline in response to the higher price contributing to the stabilisation of lake levels and *then* prices would decline again. If such spikes occurred sufficiently frequently new generation would be built. For the reasons just described prices do not spike to the efficient level and there is limited visibility of prices or ability for consumers to alter their behaviour (in a way that rewards that change in behaviour).

We know that during times of shortage the demand curve fails to intersect with the supply curve. This problem would be eliminated if demand bids were used in price formation. Even under 'normal' conditions (i.e. non-shortage) enabling demand participation in price formation could improve the market outcome by lessening buyer's remorse, where a consumer would not have purchased electricity at the prevailing market price. This will allow them to signal their real preferences to the market. Figure 5 illustrates the effect.

Figure 5 Price formation with demand bids – shortage and normal conditions



The demand-side bidding and forecasting initiative already underway will go some way toward this, with some participants able to see the likely effect of their bid preferences on price in the pre-dispatch schedule. This is expected to have some effect on final demand and the need for supply-side investment. However, this initiative does not encompass all load, for example retail customers load management would not be enabled by this initiative.

Creating the ability for consumers to see and respond to prices is a critical part of this framework in order to make best use of this type of price formation process. The speed with which consumers can respond to price changes is variable. In real time it is not efficient for most consumers to monitor price and change their behaviour (their electricity expenditure does not justify this expense). Instead consumers need the ability to form price expectations and lock in their price, and/or adjust demand prior to real time. They need a forward market.

This could be a day ahead or a week ahead of real time. The choice should be based on the timeframe in which consumers make decisions and the timeframe in which prices are firm (i.e. supply is fixed barring unplanned outages or other unexpected events). Points to consider include:

- The timeframe for planning generation and transmission outages.
- The timeframe in which hydro storage becomes known with relative certainty.
- The timeframe in which industrial and commercial consumers can change their production plans or manage their demand.
- The timeframe in which it is possible for retailers to forecast their load with relative certainty – this can be largely temperature driven.

These factors suggest you might see the wrong level of demand response a week ahead and you are likely to know much more about the generation side of the market a day ahead. In addition, hedges are available although not always at acceptable terms to the user, further out. A day ahead market would be more transparent, it would expand the options available and may help with overall hedge market liquidity.

Clearly, bids are an important part of the price formation process in the forward market. Consumers who have a hedge or other fixed volume contract should be allowed to sell their volume into the forward market (that is they would receive the wholesale forward price for demand reduction)[18] Traders would be allowed in the market, they would add liquidity and would be able to close out their position in real time. Aggregators would also be able to trade in the market, either procuring a price for their demand, or selling fixed volume contracts to the extent that they are able.

In real time those with a forward position could correct it – again a consumer who finds they have too much supply (i.e. given the real time spot price they would prefer to reduce their electricity consumption) could offer their contracted volume back to the market if they are able to respond in real time.

This mechanism may encourage innovative retail products, and custom consumer compensation schemes under the PCC demand buy-back regime (either by the retailer or an independent aggregator). It would also provide a mechanism for demand aggregators to enter the market with controllable commercial load (like air-conditioning in office blocks).

[18] Note that in general the market would operate like the real time market, i.e. the demand side would not receive any side payment for responding to price signals in their demand.

Table 9 Recommended alternative to price floors: a forward market
Establish a day or week ahead power exchange with mandatory participation for wholesale market participants
Form half hourly nodal prices based on the intersection of the curve formed by demand bids and the generator offer stack.
Pay supply and charge demand $Q_1 \times P_1 + (Q_0 - Q_1) \times P_0$
Where Q_1 is the quantity offered by generators or bid by load in the forward market at the nodal price P_1 Q_0 is the quantity produced by generators or consumed by load in real time P_0 is the real time nodal price
Allow traders, including demand aggregators, to participate in the day ahead market. Note that traders would not need to participate in the real time market or hold a physical position to do this, but the generator and load with which they trade would.
May need a penalty for not completing your forward trade (e.g. NYISO confiscate real time payments if $Q_0 - Q_1 > 0$)
Allow load that holds a fixed volume contract to offer it into the forward market (i.e. sell).

Examples of day ahead markets

Day ahead markets are not unusual internationally, and Nordpool and PJM, both large well-functioning markets, have them. Like New Zealand, Nordpool is an energy-only market.

1.9 Nordpool

The Nordic electricity exchange, Nordpool, covers Denmark, Finland, Sweden, and Norway, with effective links to Estonia and Germany. The market is divided into several bidding areas which are based on grid bottlenecks, for example western and eastern Denmark, however, in the absence of grid constraints binding there is a single system price.

It features a day ahead market, Elspot, with a gate closure of midday on the day preceding trading, and a time balancing market, Elbas, with a one hour gate closure prior to physical dispatch.

Elspot, the day ahead market, has prices that are set at the intersection of demand offers and supply bids – a process known as a double auction.

Elbas also is fully open to producers and consumers and even trading participants with no physical offtake from or injection into the grid.

Finally, any imbalances between the Elbas position and real time dispatch are dealt with by Transmission System Operators (TSOs) putting together an up and down regulation merit order.

1.10 PJM

PJM, the world's largest exchange also has both a day ahead and a real time balancing market, with full nodal pricing.

The day ahead market allows purchasers, generators and traders to commit to positions for the next day's trading at half hour intervals. A full reserve market is co-optimised at this time. Note that, like for Nordpool, so-called virtual bids of traders are allowed in these markets, which has boosted liquidity. A participant who bids a virtual position in to the market in the day ahead market closes out his position on the balancing market.

All generator bids are carried over from the day ahead market to the real time market, however, these may be revised.

It has been shown that as you would expect, the pricing outcomes in the day ahead and balancing markets have converged over time, since the start of the day ahead market in 2000[19]. This suggests that a day ahead market would provide an excellent price signal to users.

Cost benefit analysis

1.11 The Authority's analysis of its price floors

The cost benefit analysis undertaken by the Authority is not disclosed in a great deal of detail in the consultation paper. However, some additional information has been made available.

The benefits of the price floors are estimated using a constructed 'equilibrium' or steady state world, based on a market simulation model developed by Concept Consulting. The modelling assumes that there is some level of price suppression during periods of

[19] Experience with PJM Market Operation, System Design and Implementation, Andrew L. Ott, Invited paper, IEEE Transactions on Power Systems, May 2003

shortage, that leads to a sub-optimal outcome in which the system is not sufficiently reliable. The price floors are estimated in such a way that the model indicates that an efficient level of reliability would be achieved if prices were at or above the floor. While this is internally consistent analysis, it is based on assumptions and modelling of a largely 'black box' nature, which makes it difficult to evaluate. The level of reliability that is assumed to be efficient is based on the winter capacity margin from the Electricity Commission's Security of Supply Policy.[20]

1.11.1 Some issues to consider

The additional information provided by the Authority notes that "the cost benefit analysis in the consultation paper focussed mainly on *capacity* adequacy"[21] This seems surprising as both public conservation campaigns and rolling outage load shedding events are clearly *energy* adequacy problems. This categorisation is acknowledged by the Authority in section four of the main consultation paper, where the underlying problem is discussed.[22]

We know that there is no such shortage at present. In fact, the System Operator's 2011 assessment states that: "with investment in committed, all "high probability" and most "medium probability" generation, it is projected that New Zealand and South Island Winter Energy Margins could be attained over the nine-year horizon" in terms of the winter capacity margin the assessment is that high probability investment is needed to 2015 to maintain the target margin, with medium probability investment required after that.[23]

Based on the System Operator's assessment it seems reasonable to suppose that the steady state that the analysis is based on and hence the benefits estimated in the Authority's analysis will not be available until at least 2015 and probably not for nine or more years (given that we do not realistically know what new generation is likely to be planned a decade from now). This suggests that even allowing the benefits to phase in

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[20] The Electricity Commission determined a winter capacity margin and winter energy margin based on its assessment of the level that would miminise the cost of reserve energy and/or capacity and the expected cost of unserved energy

[21] Supplementary information for scarcity pricing consultation: response to request for further information #1, 26 April 2011, emphasis in the original.

[22] See the Authority's diagram as replicated in section 1.5.

[23] Annual security assessment 2011, prepared by the System Operator, January 2011.

over 5 years may be optimistic.[24] This is consistent with the Authority's supplementary information, which notes that the analysis focuses on the longer term effects of the proposals.

The costs and benefits of the different proposals are not separable in the analysis presented. In fact:

- The analysis does not appear to consider the costs and benefits of the proposed spot exposure disclosure regime at all.
- The Authority notes in the draft version of the consultation paper that was prepared for the *Scarcity Pricing Technical Group,* that "it is not clear that an additional price floor during PCCs will yield *incremental* reliability benefits".[25]
- In respect of the price floor for rolling outages the Authority noted that the potentially severe financial consequences give rise to doubts as to whether it could actually be applied in practice at all.[26]

The Authority presents two possible counterfactuals, one in which the highest offer price (without floors) is $3,500 and the other based on the current Whirinaki offer price of $5,000. Since the change in the Whirinaki offer has changed market behaviour, and there is no fundamental reason that it should change back to the old behaviour (and in any event prices went above $3,500 even before the change), a $5,000 price is the better representation of current market behaviour. Indeed this may be conservative as generators have recently been willing to offer at prices far above this assumed maximum.[27]

The Authority has not yet determined how the price floors would be implemented and is still discussing this with the System Operator. Nonetheless they have assumed a total present value of costs of $7 million. It is difficult to know whether these costs are a reasonable estimate or how they might be attributed to the various measures in the proposal. For example, it would be possible to argue that given the likelihood of employing the other mechanisms is lower, most (or all) of the cost should be attributed to the PCC floor. On the other hand, if one were to remove the PCC floor from the list of

[24] The Authority presents 3 phasing alternatives, the five year analysis has a phase in of 0%, 10%, 20%, 60%, 80%, 100% of the benefits in the first six years respectively.

[25] Para 150, emphasis in the original, the draft is dated 9 March 2011.

[26] Para 147.

[27] On 26 March 2011 Genesis Energy was dispatched at offer prices of between $19,000 and $20,000.

proposals and still implement the other three floors presumably the System Operator's implementation cost would not change much, so the incremental implementation cost would be fairly small.[28]

The Authority's analysis does not take into account a number of other concerns that are raised by their proposal, and which will impose costs on the economy, including:

- The high prudential requirements associated with floor prices.
- The possibility that some generators will use localised market power to impose extreme prices during times of shortage or near shortage.
- The barrier to entry for new retailers associated with their (in)ability to obtain adequate hedge cover.
- A higher level of spill and thermal fuel burn associated with increased risk aversion on the part of generators, causing higher than efficient prices even when the floor is not operating.
- The possibility of stranded assets if too much new plant is built because the price floor is inefficiently high.
- An inefficiently high level of demand reduction as a result of higher prices (associated with transitory market power during near misses, inefficient levels of spill/thermal fuel use and inefficient investment). This would have a real effect, in other words the level of production in the economy would decline impairing GDP. These effects are not transfers and should not be ignored.[29]

In addition the mechanics of implementing any price floor could impose additional costs and inefficiencies that have not been considered (additional to the market clearing engine costs). For example, if an offer floor was introduced (as opposed to a 'price' floor) and all generators offered at the floor then those closer to load would be dispatched, resulting in the unfair shutting out of generators further from load from generating, and possible security of supply issues if fuel stocks were run down at some stations.

A further issue to consider is that "a price floor would make hydro/thermal dynamics harder to model with standard industry tools (e.g. Spectra)."[30] Amongst other difficulties this might create, presumably this will make judging the effect of the price floors and

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[28] This is not to say that the ongoing cost would be small as arguably the key reason for frequent review is the PCC floor which is most likely to be used and therefore influence behaviour.

[29] See the Electricity Commission paper *Price floor during scarcity* 30 September 2010 for a summary of these issues.

[30] *Price floor during scarcity,* Electricity Commission, 30 September 2010 para 3.1.4 (b)

making any adjustments to the level of the price floors more costly and prone to regulatory error. This exacerbates the uncertainty associated with regulatory intervention.

As already noted, the adverse precedent created by the Authority setting prices based on its view of generators' fuel management may also create costly regulatory uncertainty.

1.11.2 Assessment of the result

Taking all this into account, the $19 million net benefit indicated by the Authority seems very optimistic.[31] This is equivalent to an average annual (undiscounted) net benefit of $2.2 million.

This benefit is too close to zero to be meaningfully positive when you take into account all the unquantified costs listed and the possible costs associated with regulatory error. For example, the Authority has indicated that it estimates the net cost of setting the floor too high, causing excessive hydro spill, to be $2-3 million per year. Allowing for this cost, the price floor proposal is at best neutral. [32]

While the Authority may argue that it will avoid this cost by setting the floors at the exactly optimal level it cannot avoid all the unquantified costs and it is not unreasonable to think that these will be in excess of $2.2 million a year.

It should also be noted that the benefits (as given) may not be available as quickly as the Authority has assumed. Given the System Operator's assessment, we might suppose that no benefit is achieved until at least year 5, in which case the net present value is a cost of $1m.[33]

1.12 A forward market

Papers prepared by the Electricity Commission illustrate why the market is best placed to set prices and that it can do so efficiently.

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[31] This is the total net present value of benefits associated with price floors with a five year phase in and assuming that $5000 is a reasonable estimate of the current 'ceiling' on offer prices.

[32] Para E132 of the Consultation paper. The figures in the table do not add giving rise to the uncertainty about the actual size of this potential cost. At $2m per annum the NPV (based on the spreadsheet released by the Authority) is just $1m.

[33] We have assumed the same phasing as the Authority over years 5-9 to derive this result.

> *The underlying question is: who is better to determine what the spot energy price should be – the market or the regulator?*
>
> ***If the view is that the market is best placed to determine the price,*** *then the regulator should seek to price in externalities, deal with situations where the market cannot clear (i.e. capacity shortfall), and then allow price discovery to proceed without further intervention. Failure to do so may lead to mispricing, and hence inefficient generation investment and operation – ultimately resulting in unnecessarily high prices to consumers. (Electricity Commission, Sept 2010)*[34]

The Electricity Commission prepared a paper in October 2010 that illustrated the estimated the effects of VoLL pricing on mean wholesale prices.[35] Seven scenarios were considered with four possible capacity scenarios. It is shown that during an energy shortage if prices are maintained (rather than collapsing) there is just sufficient (i.e. the correct) incentive for thermal peaking capacity to be built at around 800MW capacity margin. This supports our view that if the market correctly signals the price, it will induce an efficient response.

1.12.1 Assessment against the Authority's statutory objective

Limb 1: promoting competition in the electricity industry for the long-term benefit of consumers

The Authority has determined that the effect of their scarcity pricing proposal on competition is uncertain due to issues with the obtaining reasonable hedge cover.

This is not an issue for our proposal which would:

- Increase the availability of forward cover, reducing barriers to entry
- Encourage new forms of participation, such as traders and demand aggregators
- Reduce localised market power by enabling the demand side to see and respond to prices

This proposal is therefore unambiguously pro-competitive and preferable to the price floor.

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[34] Price floor during scarcity, prepared by Electricity Commission, 30 September 2010, paras 4.1-4.2.

[35] Price effects of scarcity pricing, Electricity Commission paper prepared for the Scarcity Pricing and Demand Buyback Technical Group, 14 October 2010.

Limb 2: promoting reliable supply in the electricity industry for the long-term benefit of consumers

The Authority's proposal is expected '*on average*... to promote the achievement of a *more* efficient level of reliability'[36]. It acknowledges that the price floors could be set too high or too low and hence there will be a review at least three yearly.

Our proposal will allow consumer preferences to determine the optimum level of reliability as they will signal their willingness-to-pay. This level will also be achieved as suppliers will be able to price electricity according to consumer preferences.

The need for ongoing review is eliminated because changes to preferences will automatically be incorporated through changes to participants' behaviour.

A forward market makes a stronger contribution to limb 2 of the statutory objective than a price floor does.

Limb 3: promoting the efficient operation of the electricity industry for the long-term benefit of consumers

The Authority does not identify specific efficiency improvements associated with their price floor proposal, simply reiterating that the level of reliability will increase, and based on their estimates and assumptions the result will be closer to the efficient level of reliability.

The whole system cost will be lower under our proposal than a price floor since prices will fall during 'normal' (i.e. non-shortage) periods, meaning that less capacity is built overall. This is an efficiency improvement.

The price floors are expected to stress participants' prudential arrangements with the clearing manager, which are based on 55-60 days of the clearing manager's net exposure to that participant. The forward market will not do this for two reasons:

- The forward market could potentially be settled more often than monthly since it does not depend on metered data. This would reduce the level of spot market trading and hence prudential requirements.
- Even if the forward market is settled monthly, the level of prices is not expected to be sustained at a high level for as long under this arrangement (i.e. the average will be lower) and the quantity of electricity bought when prices are high is expected to fall more than under the Authority's proposal (since the mechanism is

[36] Consultation Paper para 203 emphasis added.

will directly facilitate demand-side participation). This means that prudential requirements will be lower than under the Authority's proposal.

The forward market will also contribute to meeting other requirements under section 42 of the Electricity Industry Act 2010 specifically:

- (d) mechanisms to allow participants who buy electricity on the wholesale market (commonly called the demand side) to benefit from demand reductions and
- (g) facilitating, or providing for, an active market for trading financial hedge contracts for electricity

The credibility problems that the Authority outlines in its consultation document associated with whether an administered price will really be imposed are eliminated by using a market mechanism that internalises the price computation.

By using market mechanisms rather than estimates and assumptions, and by taking an integrated approach to a number of problems the efficiency of the industry will be enhanced.

Overall then a forward market does a better job of meeting the Authority's statutory objective than the Authority's proposed price floors.

1.12.2 Cost benefit analysis

We have already outlined the difficulties in determining the level of costs and benefits attributable to the price floor during a PCC recommended in the Authority's consultation paper. This difficulty is compounded when trying to compare their result with another mechanism.

Based on their framework, the benefits of a forward market are at least as great as a price floor. The price floor is based on an assumed optimum level of reliability and estimates of what the price should be to provoke that level of reliability from generators, and then the credibility of the threat that an administered price will be imposed. The forward market does not make any of these assumptions or threats, it lets market participants identify and achieve the efficient result based on their revealed preferences.

There is no credibility problem because there is no regulatory threat. It also eliminates the need to make the estimates, review the efficacy of the floors, and their impact on market (cost savings).

Figure 6 Prices during a shortage

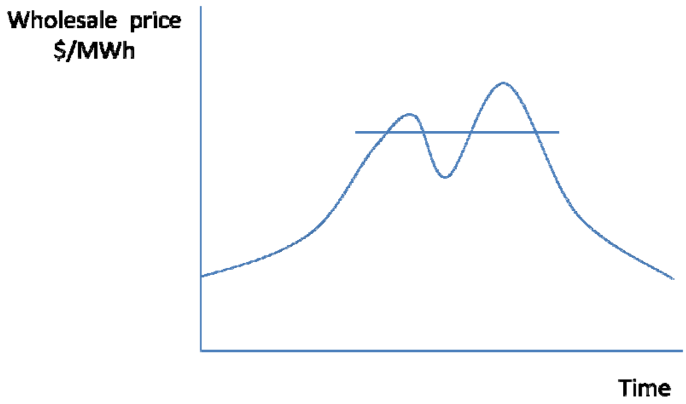


Figure 6 shows the level of prices across a year when there is a shortage. This is illustrative only, but highlights the problem of imposing a high level of price across a period of time when the true price (based on supply and demand conditions) fluctuates. When the price floor is above the efficient level then demand will be inefficiently low (because purchasers will respond to the 'too high' price). This could occur during particular times of the day and also during a shortage 'period' if there are some inflows or demand reductions followed by a second period of high demand or low inflows.

We have already noted other benefits of a forward market over a price floor but for completeness we repeat them here:

- Competition enhanced by encouraging new forms of participation.
- Competition enhanced by reducing barriers to entry by providing increased risk management tools and reducing prudential requirements.
- Less capacity is built overall, lowering the total system cost, as investment in new generation is postponed by the market identifying cheaper demand-side alternatives.
- Other s.42 matters are addressed or partially addressed reducing overall regulatory cost.

On the cost side, no change is required to the market clearing engine since it is already capable of solving using the demand-side and a day ahead market was part of the original market design. Additional resources would be required from participants, the system operator and the clearing manager to handle two sets of market transactions. It is not apparent that these would be large considering systems are already in place to deal with the spot market (i.e. the costs would be incremental rather than requiring the establishment of new systems).

Table 10 Costs of a short term forward market relative to a price floor

Type	Frequency	Forward market	Price floor
Implementation cost – regulator	Initial	Some rule setting costs but relatively low since the mechanism is largely in place	Costs associated with setting the level of price floor, negotiating with SO over implementation details, code changes
Implementation cost – System Operator	Initial	Some set up costs – a day ahead market was part of the original market design, so it is not apparent that these would be particularly large, forecast prices are also currently prepared up to 36 hours ahead	Estimated by the Authority at $4.5m. The SO is required to make changes to the market clearing engine to implement the price floor
Set up cost – market participants	Initial	Some cost associated with making two offers/bids. Relatively low as offers and bids are already required up to 36 hours ahead	No system costs
Ongoing cost – regulator	Ongoing	Only if rule changes are required	Ongoing costs of monitoring, formal 3 yearly review, re-estimating floor levels
Operating cost – System Operator	Ongoing	System maintenance costs	Depends on the level of automation when price floors are imposed, if adjustments are manual this would impose higher ongoing costs on the SO
Operating cost – market participants	Ongoing	Some increase in costs due to requirement to make two bids/offers	Low, although some costs associated with risk management changes such as higher hedging
Higher prices during a shortage (transfer)	Ongoing	Transfer between market participants no net cost	Transfer between market participants no net cost
Allocative inefficiency associated with generators using localised market power during shortage or 'near miss'	Ongoing	N/a	Generators may alter their behaviour in order to trigger a floor (if they are long in generation) and/or set extreme prices during shortages

Type	Frequency	Forward market	Price floor
Setting price floor too high	Ongoing	N/a	Inefficient reduction in demand will occur. The Authority has estimated this cost at $1-3m per year, although this is probably conservative as the estimated reduction in shortage cost appears much too high. It is not clear how the shortage cost was derived given a high price floor results in storage in excess of an optimal level (so the chance of shortage is already low).
Implementation inefficiencies related to mechanism to set floor	Ongoing	N/a	Depends on the details of implementation (e.g. an offer floor may lead to unintended consequences for dispatch and hence security of supply concerns)
Lower retail competition due to lack of hedge products and higher prices	Ongoing	N/a	Retailers may choose to not enter/exit early due to costs associated with probability of floor being triggered and lack of available hedge/risk management products
Lower retail competition due to prudential requirements	Ongoing	Prudential requirements will rise but by less (possibly much less) than under the price floor	May see extreme increase if floor is triggered.
Higher spill and thermal fuel burn due to increased generator risk aversion	Ongoing	N/a	This proposal is intended to make hydro generators set a higher price for their storage. This may result in increased spill and higher overall system cost.
Regulatory uncertainty – modelling costs, credibility	Ongoing	N/a	Could be considerable. The Authority acknowledges the floor proposed for a rolling outage may not be implementable in practice; three yearly review means ongoing uncertainty; depending on the details of implementation hydro/thermal dynamic modelling may become difficult; sets an adverse precedent of the regulator setting the price based on its view of generator fuel management.

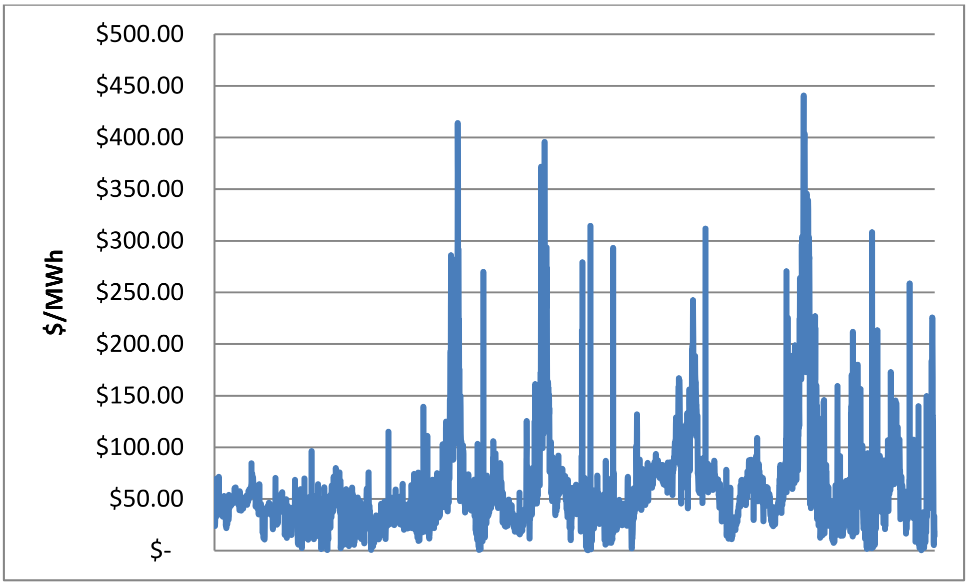
Table 11 Benefits of a short term forward market relative to a price floor

Type	Frequency	Forward market	Price floor
Higher wholesale prices for generators (transfer)	Ongoing	Transfer between market participants no net benefit	Transfer between market participants no net benefit
Lower frequency of foregone consumption due to voluntary, and instructed load shedding and rolling outages	Ongoing	At least as large as a price floor as level is set by revealed preference rather than administered estimate	Estimated by the Authority as $2.2m per year.
Reduced buyers' remorse due to lower than expected ex post prices	Ongoing	Buyers can see and 'lock in' prices ahead of time in all trading periods	Some benefit as prices will be above floor during some periods
Lower system cost	Ongoing	Less generation will be built as lower cost demand side alternatives will postpone investment	If price floor is set too high too much new generation will be built increasing system cost and potentially stranding assets
Lower hedge costs (search and transaction)	Ongoing	A regular, transparent mechanism for short term hedge cover will be available. This may assist the development of longer term contracts	This may exacerbate the reported problems of getting 'reasonable' terms and conditions for hedge cover as long generators will have increased opportunities to exercise transitory localised market power
Greater perceived security of supply	Ongoing	The intangible costs of disruption, and inconvenience will reduce as consumers can reveal their willingness-to-pay	Depending on the derivation of the price floors these avoided costs may be captured
New forms of participation	Ongoing	Traders and demand aggregators may enter the market, promoting competition	N/a
Contributing to other new matters under s.42	Initial	A forward market would contribute to s42(d) – demand side participation; and s42(g) – facilitating active trading of hedges	N/a

Appendix A Price formation

The spot price is determined in the electricity market by matching metered demand with the supply stack ex post. The price level is determined by the level of offers made by generators. The structure of the market encourages them to set their offer at the short-run marginal cost of their plant (predominantly fuel costs). To some extent offers are also tempered by political and social expectations; this has meant that even in times of shortage, prices have not averaged above $500 for any single day, with very isolated incidences of cleared offers in excess of $1,000.

Figure 7 Daily average price at Haywards 1996-2010



Under normal (i.e. non-shortage) conditions prices are set at the highest offer dispatched to meet demand. This is illustrated in Figure 8, the price is P^* and generators earn quasi-rents, i.e. prices are above most generators' marginal cost, allowing them to recover part of their fixed cost. This ensures that over the long term generators recover their average cost.

Figure 8 Normal price setting

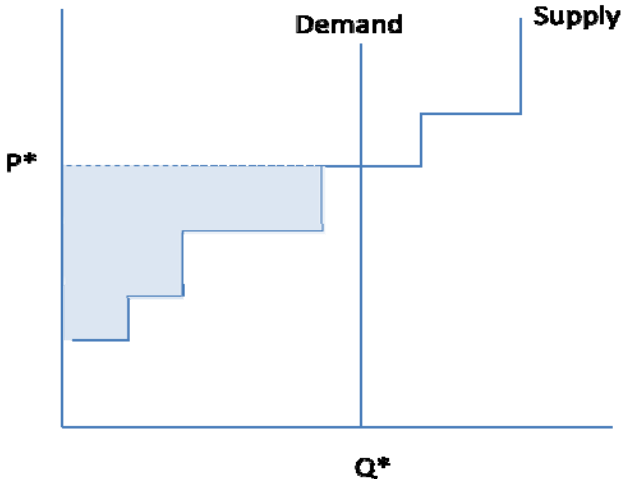


Figure 9 shows what happens when unconstrained demand (Q^u) exceeds supply. Demand is forcibly reduced to the level of supply (Q^c) and price is set at P^c which is the highest offer. This effectively ignores the value of unmet load. The price does not reflect the fact that there is a shortage. There is no price signal to suppliers to increase generation. Likewise consumers do not see an accurate reflection of the cost of supplying their unconstrained (actual) demand. A similar process occurs implicitly during a PCC. Demand is voluntarily curtailed (i.e. the curve shifts left) and prices fall to reflect the intersection of actual demand and the offer stack. Prices do not reflect the conservation efforts of consumers.

This is the justification for the compensation scheme recently implemented by the Electricity Authority to reward small consumers for the average value of savings. It is a somewhat clumsy mechanism because it cannot take account of actual individual behaviour, nor does it reflect real time responses as the payment is based on historical data. It would be preferable to improve price formation and consumers' ability to see and respond to the price.

Figure 9 Demand curtailment – current pricing

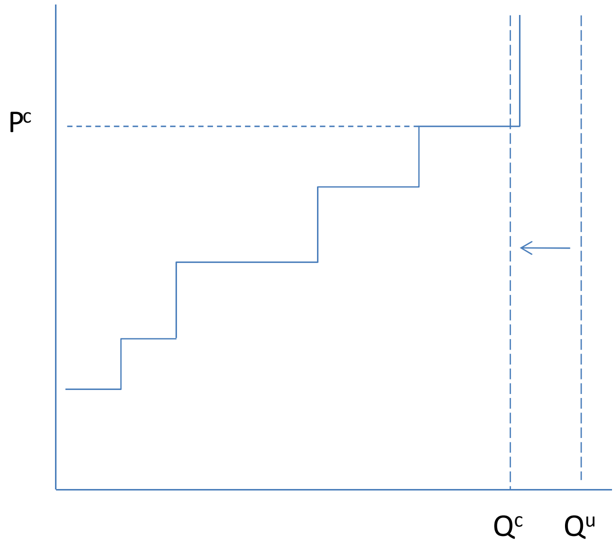


Figure 10 Demand curtailment – scarcity value

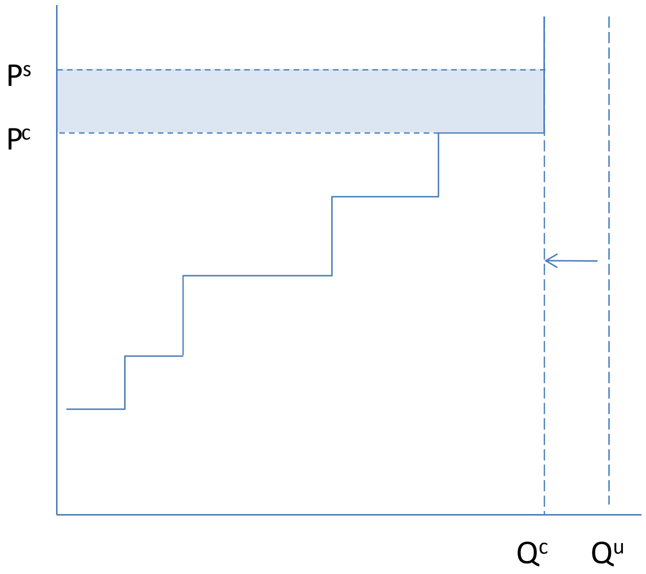


Figure 10 demonstrates a preferable outcome from a price formation perspective, price rises to P^s and generators receive a scarcity rent indicated by the shaded area. This is a return higher than is necessary to cover total average cost and attracts new generation capacity to the market. This is the situation that the Electricity Authority is attempting to mimic with their price floors during a PCC. P^s is not currently well-defined though, as consumers' valuations of supply are not observable. It is intended that a price floor will reduce the incentive for retailers and major users who are exposed to the spot price, to call for a PCC in order to reduce spot prices (by suppressing residential demand). If a PCC does occur (due to the low storage levels trigger as prescribed in the customer compensation provisions) the floor price would be the spot price and would reflect the value to households of reducing demand. As we understand it, this arrangement is intended to reduce the probability (and possibly duration) of a PCC.

Figure 11 Indeterminate price

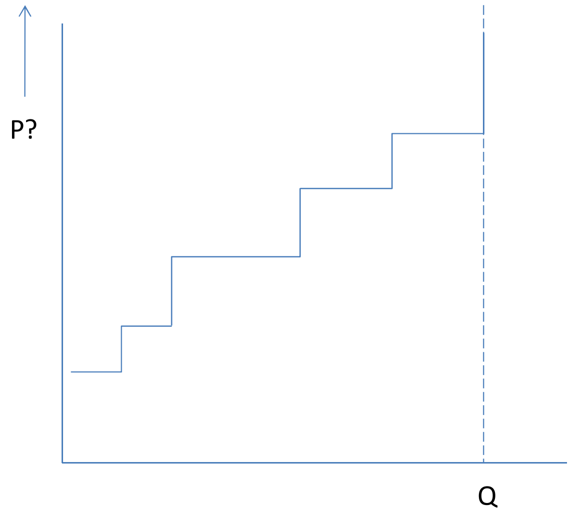


Figure 11 illustrates a further problem with the current price formation process, which is that at the boundary of supply the price is indeterminate because the supply curve becomes vertical.

Appendix B Current initiatives relevant to security of supply

B.1 Fuel supply

B.1.1 Security of supply monitoring

From 1 November 2010, Transpower, in its role as system operator, become responsible for monitoring security of supply. The monitoring looks at generation availability, demand trends, transmission availability and wholesale prices. A risk of a shortage is continually assessed based on those factors. The weekly publication of the assessment assists participants to formulate appropriate bids and offers.

B.2 Generation capacity

B.2.1 Monitoring of progress to a liquid hedge market

The minister of energy has set a target for the five generators with over 500MW of capacity to achieve by 1 June 2011 an active market for exchange-traded electricity contracts. The Authority is set to receive by 20 May 2011 a report from an external expert on the progress achieved and to set out any necessary actions to achieve this goal.

A liquid hedge market is considered one of the missing pieces of the New Zealand electricity market. A market would assist in the new entry of participants at all levels of the supply chain, as well as assist purchasers with their investment decisions and risk management. Furthermore, participants who have not been able to procure hedges have an incentive to lobby for interventions to suppress necessary price signals at times of shortage. A liquid hedge market would commit the counterparties to transactions to positions that accurately reflect the risk of higher prices, while not weakening the signalling effect of those high prices in real time.

B.2.2 Review of the Whirinaki reserve energy offer

On 1 March 2011 the offer price for Whirinaki was revised. It is now set at $5,000/MWh during normal periods[37], and at its SRMC during supply shortages (but only if the system operator has confirmed that there is sufficient supply). Presumably the offer at SRMC would be to ensure that Whirinaki is fully dispatched at those times – which approximates

[37] This stand by offer price is currently under review by the Authority.

how a commercial owner might operate the plant. In other cases the offer at $5,000 is effectively a price floor should all generating facilities in the country be required for dispatch of energy and reserve.

B.2.3 Instantaneous reserve dispatch

On 18 February 2010 the Electricity Commission made a number of urgent rule changes to improve the incentives for instantaneous reserve (IR) providers and to try to ensure that prices of reserve and energy would not be suppressed during shortage events. These, and other concurrent, measures included:

- Constrained on payments for IR.
- Reinstatement of variable RAFs.
- Changes to SPD model variables to ensure that prices are not suppressed if insufficient reserves.

B.2.4 Customer buyback scheme

On 1 April 2011 the Authority introduced a customer buyback scheme whereby in the event of a PCC each retailer would pay $10.50 per week to qualifying customers. Certainty is now provided for when a PCC will occur, which is when the risk of a hydro shortage has surpassed 10%. One of the stated advantages of the scheme is that "it should [...] result in electricity conservation campaigns occurring less frequently than in the past"[38].

The Authority's own analysis of December 2010[39], when spot prices rose to higher than expected given lake levels makes this explicit link as well:

> *"The prospect of the proposed customer compensation scheme being adopted by the Authority in the first quarter of 2011 may have intensified the level of caution exhibited by generators when considering hydrological conditions in early December 2010."*

The Authority concluded that the spot price rise was appropriate and that it achieved the right outcomes (demand response, scheduling of thermal plant ahead of hydro).

It would therefore be apparent that a change to the probability of future hydro events has already taken place.

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[38] From the EA summary document **Customer Compensation Scheme during Public Conservation Campaigns**, 3 March 2011

[39] **Wholesale Electricity Prices: December 2010,** 28 January 2011

Qualifying customers for the buyback are those with a category 1 or 2 meter with at least 3,000kWh of consumption (excluding commercial customers). The payment is provided regardless of whether the customer has made savings. Consumers may also opt for a retailer alternative linked to actual savings.

The System Operator is responsible for validating when a public conservation campaigns (PCC) starts (mandated at 10% risk of a shortage), and when it ends (when the risk of shortage has fallen back to 8%).

It has been argued that providing certainty as to when a PCC ban be started will reduce the incentive for retailers to call for such campaigns. It would therefore encourage retailers to use commercial arrangements to manage their risk and contract demand response; it would encourage investment in dry year generation capacity and promote greater use of hedging.

B.3 Transmission capacity

B.3.1 Locational price risk management

The Authority is still seeking feedback on its proposal for a financial transmission right between the north and south islands. It has been argued that the introduction of such a product will support a liquid hedge market and make it possible for participants to manage their locational risk should scarcity pricing be established on an island basis. Improved retail competition is the most important benefit expected. Implementation of the product is expected in early 2012.

Analysis from the EA indicates that a FTR would limit the market power that a generator might exert in a constrained region. At present, the limited ability of the demand side to react to high prices can result in detrimental outcomes that is a variation of the problem that has been identified as the driver of scarcity pricing: where consumers of electricity are locked into high prices that they would have been willing to react to.

B.3.2 Transmission pricing methodology

Transmission pricing methodology is relevant for the provision of signals to decrease peak demand and for the construction of generation units where they can be best sited. The greatest effect of transmission pricing is on capacity, however, to the extent that when capacity is constrained the total amount of energy served is impacted, there is a direct relevance to shortages.

B.3.3 Grid support contracts

In the winter of 2008 Transpower undertook a full trial of a grid support contract scheme in the upper South Island. While the main purpose of the scheme was to deal with transmission capacity issues it was evident that it was possible to elicit a demand response. However, the purpose of this trial was not to achieve a reduction in total energy consumed but to decrease peak demand in critical periods.

B.3.4 Investigation into the value of unserved energy

The Electricity Authority has yet to publish a report on the results of a survey into the value of unserved energy, which has been set at $20,000/MWh since 2004. The value of unserved energy is used for future planning so that the effect of unmet demand can be assessed when looking at alternative investment options.

B.4 Demand response

B.4.1 Demand side bidding and forecasting

This proposal, which we understand will be introduced in early 2012, will enable participants who are able to respond to spot prices to see the likely effects of their expressed preferences in the pre-dispatch schedules. One of the stated (quantifiable) benefits is a reduced dispatch cost as a result of an efficient response to high prices. It is considered also that the demand response could defer investment in generation and transmission.

Each Grid Exit Point (GXP) is to be designated as conforming (predictable load) or non-conforming. The system operator will prepare demand forecast for conforming nodes (i.e. no bidding necessary) but purchasers at those nodes who expect a change must communicate it to the System Operator. Purchasers can opt to submit “differencing bids” at those nodes – but these are used only for scheduling, not dispatch.

A new schedule (the price responsive schedule, PRS) would be used in place of the PDS and SDPQ based on bids at non-conforming nodes. A non responsive schedule (NRS) would be published at same time.

While this initiative is relevant to the operation of the market in real time it is not probable that it would have an effect on conservation of fuel stocks pre-shortage. However, it is relevant to the development of a demand side in the electricity market.

B.4.2 Property rights for load management

The question of who owns the rights to manage load is important as it is widely agreed that effective load management can defer investment in generation, transmission, and distribution assets and provide system security for the benefit of consumers. The Electricity Commission released a report in 2009 that concluded that the question of property rights of load management was not a barrier to successful use of load management.

Effective deployment of load management requires that the technical assets exist to allow for it; that the incentives exist for parties to enter into contracts; and that such contracts are widely understood.

B.4.3 Dispatchable demand

In this case, parties who choose to participate could submit some of their load for dispatch much like generation is now. As is affirmed in the Electricity Commission's working draft on the subject (of 3 September 2009) allowing purchasers to participate could achieve more efficient pricing, which would itself "[lead] to a more efficient allocation of resources in both the short and the long term".

This work programme specifically mentions links with the demand side bidding and forecast programme, some form of real time pricing, and promotion of so-called smart meters.

Dispatchable demand would be an opt-in process, with marginal bids able to set final prices. Dispatch instructions would be provided to participants in the dispatchable demand process, with the possibility of constrained on or off payments.

It has been stated that dispatchable demand would provide a lower cost means of responding to tight energy market conditions and would defer investment in supply side assets.

Some participants that could potentially respond to prices have voiced concern about the necessity of having to respond to dispatch instructions in real time. For that reason, some sort of day ahead market would be preferable to them so that they can plan ahead for the next day's production.

For the same reasons as stated for demand side bidding and forecasting, this initiative will not have a major effect on hydro conservation. There are also some major implementation issues to ensure that consumers do meet their demand reduction commitments.

B.4.4 Review of the code related to metering

A necessary condition for demand participation is that the right sort of metering be available so that price incentives can be effectively communicated and that it can be verified objectively that a commitment entered into has been met. While the majority of consumption in New Zealand is metered with TOU (time-of-use) meters, the majority of residential consumers, who represent around a third of total consumption, do not have TOU meters.

The Electricity Commission was mindful in its review of the metering rules to ensure that it would inhibit the growth of advanced metering infrastructure and allow for the introduction of new technology. There have been some calls to mandate a roll-out of advanced meters. However, opposing views consider that mandating introduction of new meters could stifle innovation.

B.5 Other possible initiatives

In the market design review paper of 2008 a number of possible initiatives were mentioned as follows:

- Publish capacity projections
- Apply default VOLL price if demand forcibly curtailed
- Variable reserves
- Apply default price if instantaneous reserves inadequate
- Introduce Uniform Availability Payment
- Introduce Capacity Payments
- Introduce Installed Capacity Requirement Regime
- Introduce Strategic Capacity Reserve Regime

Some of these have been progressed further as is evident from the previous section, however the last four, which relate to capacity, have not been pursued further. The energy-only market is expected to remain.

Looking much further into the future, low cost distributed generation would have a significant impact on the way the industry is set up. The current costs of such generation preclude it being assessed as a serious alternative at the present.

Appendix C International experience in electricity markets

Other electricity markets deal with the suppressed demand issue in a number of ways. This section looks at some of these measures with some sub-options listed.

C.1 VOLL with Scarcity pricing

This is one of the more common approaches. However, the range of scarcity prices is quite wide depending on the electricity market. The rules for the application of the scarcity price also vary widely. The following is a list of some of those options:

- Applies for any shortage
- Applies for specific events
- Progressively brought in depending on probability of shortage
- Actioned only when shortage happens
- Reserve market always maintained for pricing purposes

Most commonly the applied price is a cap

C.2 Capacity mechanism

Capacity mechanisms are also a fairly common feature of markets. In some markets there is a market type arrangement whereby capacity credits are auctioned. It is not the only type of arrangement, however. These are some of the possibilities:

- Capacity credits are auctioned
- Centrally set price for capacity credits
- Mandated objectives
- SO owns generation
- Govt owns generation

It is argued that capacity type arrangements can lead to gaming and to inefficient market outcomes. It has also been argued that capacity markets can cause the wrong level or type of investment with consequences for the energy market.

C.3 Dispatchable demand

There are several types of dispatchable demand as follows:

- Day ahead
- Real time

- Interruptible load

Of the list, interruptible load is probably the most developed form of dispatched demand, however, day ahead participation of demand is not at all uncommon. Real time dispatch of demand in the energy merit order is a more difficult problem to solve as there are several big technical and rules issues that are hard to deal with.

C.4 Demand response

Demand response is achieved in a number of ways outside of dispatchable type demand. Most residential tariffs are of a fixed price variable volume nature meaning that the pricing signal is unrelated to the scarcity conditions at hand (except to the extent that the risk of a shortage is priced in). These are some of the possible measures:

- Half hourly tariffs
- Spot price exposure
- Other tariff variation (night/day/winter/summer)
- Peak pricing
- Demand buybacks
- Ripple control (demand displacement)

Note that of the list, some of the measures are only effective in displacing load, that is, they deal with short term capacity issues. Demand buybacks, and spot price exposure will have an effect on the amount of energy consumed. Seasonal tariff variation will only be effective if the tariffs are set at frequent intervals (e.g. monthly) so as to reflect the prevailing conditions.

Table 12 Different measures

Market	Scarcity Measure	Capacity Market	Demand side in dispatch	Other
Chile	Additional payment	Administratively determined payments		The market operator can set an offer price cap
Nordpool	Prices increased to cap if capacity reserves called on	Energy only	Day ahead market with demand dispatched	TSO owns peaking generation; Nordpool can pay large customers to reduce consumption
ERCOT	Capped payment of $3,000/MWh; The Rules envisage smaller generators submitting high priced offers in times of shortage. The Rules include a provision termed the Peaker Net Margin ("PNM") which appears to be designed to measure the annual net revenue of a hypothetical peaking plant. Under these rules, if the PNM for a year reaches a cumulative total of US$175,000 per MW, the offer cap is reduced to the higher of $500/MWh or 50 times the daily gas price index. The PNM reached the threshold once in 2005.	Energy only		Market power mitigation does not apply during shortages
AEMO	Offer price cap of A$12,500/Mwh set as soon as demand is curtailed or reserves decline. In addition, there is a rolling 7 day cumulative price threshold of $187,500. If this is triggered, a separate lower price cap is then applied. The cap is reviewed every two years. If AEMO sees capacity problems emerging in coming months it can contract for additional resources (although it usually seeks a demand response first) prior to involuntary demand curtailments.	Energy only		

	The AEMO can intervene in the market to direct a participant to operate plant other than in accordance with dispatch instructions, or activate a reserve contract. In this event the participant is paid an 'intervention price'. VOLL = A$12,500 The price cap operates until the next time the dispatch algorithm is run (Rule 3.9.2A)			
Singapore	Offer price cap of 0.9*VoLL. Purchase price cap of VOLL. No cumulative price threshold is included in the Rules. VOLL = S$5,000/MWh	Energy only		
PJM	Limited form of scarcity pricing; overall offer cap of $1,000/MWh for actual shortages (not for impending shortages)		Payment received to curtail in day ahead or real time; demand response can set price	PJM operates a day-ahead capacity market, in which participation is voluntary. PJM determines the maximum MW of capacity credits each market seller may offer into the market. All credits are traded at the market clearing price. Participants may also trade capacity bilaterally.