Electricity Commission
Te Komihana Hiko

Consultation Paper

Scarcity Pricing and Compulsory Contracting: options

Prepared by the Electricity Commission

October 2009

Executive summary

Purpose

1. This paper discusses a number of alternative mechanisms that are intended to improve security of supply. The Electricity Commission seeks stakeholder feedback on the alternatives, with the aim of selecting one option for more detailed evaluation.

2. In the next phase of work, the chosen option will be developed to a greater level of detail. This will facilitate a robust assessment of its costs and benefits relative to the status quo. A decision on whether to make any change to current arrangements will be made in light of that assessment.

Concerns with current arrangements

3. From a security of supply perspective, concerns with current arrangements centre on the following:

   (a) Over-reliance on public conservation campaigns to manage dry year risk;

   (b) Uncertainty over whether incentives to conserve hydro storage during dry periods are sufficient;

   (c) Declining use of reward schemes to encourage mass-market demand conservation during droughts; and

   (d) Uncertainty over revenue adequacy for plant needed to provide dry year cover, and to meet peak demand requirements.

4. Each of these issues appears to stem from a common underlying problem, which is that market participants can shift the costs of some actions onto others. This encourages over-use of some tools (e.g. public conservation campaigns) because the cost to the party seeking to trigger the tool is lower than the overall cost to New Zealand. Meanwhile, other options with a lower overall cost may struggle to earn sufficient revenue to be viable.

5. More generally, governments naturally become concerned when security of supply is threatened, and can face strong pressures to intervene. Participants can have difficulty predicting the nature of such intervention, and may therefore delay or avoid appropriate actions (e.g. load buy backs). This can lead to an unfortunate circle of participant inaction, increased government concern, and so on. It is desirable to strengthen the level of government (and public) confidence

in security arrangements. This in turn should reduce participants' concern about the potential for unpredictable intervention.

Options to address underlying problem

6. There are two broad options to address the problem discussed above:

   (a) scarcity pricing/compensation mechanisms – these seek to improve incentives for the market participants to voluntarily invest and manage resources to provide security of supply by addressing the opportunities for cost shifting; or

   (b) compulsory contracting mechanisms[1] – these seek to ensure security of supply by directly constraining wholesale market participants' behaviour (e.g. by limiting the range of choices they can make regarding hedging, generation and usage).

7. Based on present information, the scarcity pricing/compensation approach appears to be the more attractive option, provided it can be implemented in a manner that addresses concerns about the potential for increased exercise of market power/undue price volatility. Furthermore, scarcity pricing would not create a 'new' cost in a shortage event – that cost already exists in the form of unserved demand. The key change would be to make the cost of any shortage transparent to wholesale market participants – so they have incentives to minimise it, for example by procuring earlier voluntary demand reductions, or investing in additional reserve or back up generation to reduce the risk of shortage events.

8. There are two broad pathways by which scarcity pricing could be adopted:

   a) **Option A - Pure scarcity pricing** - apply VOLL pricing for actual shortage situations, but not adopt any scarcity pricing arrangements for pre-shortage events;

   b) **Option B - Modified scarcity pricing** – undertake a phased implementation, with the initial step being the introduction of administered scarcity price floors for pre-shortage situations (e.g. public conservation campaigns). VOLL pricing for actual shortage situations could be introduced subsequently if required.

---

[1] Previous papers have referred to this approach as "capacity mechanisms", as this is the term commonly used internationally to describe the approach. However, as discussed later, in New Zealand, a scheme would need to ensure sufficient *energy* adequacy as well as *capacity* adequacy. For this reason, the more general term "compulsory contracting" mechanism is used throughout this paper.

9. Both options have advantages and disadvantages, and the Commission does not have a preference between the two at this point.

10. In addition to scarcity pricing, there is potential benefit in introducing a default buyback arrangement for mass-market customers on variable volume contracts. This could address the undue incentive that retailers currently have to lobby for public conservation campaigns, to mitigate their exposure to high spot prices during extended droughts.

Next steps

11. Based on current information, the Commission intends to proceed on the following basis:

    (a) compulsory contracting should not be pursued further at this time, but should be retained as a fallback option if scarcity pricing/compensation mechanisms prove to be unattractive;

    (b) a detailed proposal for a scarcity pricing regime should be developed – based on the Pure Scarcity Pricing approach (Option A) or the Modified Scarcity Pricing approach (Option B);

    (c) a detailed proposal for a default buyback arrangement (compensation) should be developed, which would apply to mass market retail customers during any official public conservation campaign; and

    (d) to accompany these measures, work should be progressed on a range of supporting initiatives. This would include work on:

        (i) Pro-competitive measures;

        (ii) Enhanced market monitoring;

        (iii) Review of prudential and related arrangements.

    (e) the approach reflected in (b) – (d) would be developed to a point where it enables a robust assessment of costs and benefits to be made, relative to the status quo.

12. The Commission welcomes the views of submitters on these proposed next steps. The Commission will take these views into account as it makes decisions on how to move forward.

13. The Commission is mindful that the consultation papers are being released while there is an on-going Ministerial review of the electricity market. As this paper presents high-level options there will be time to consider issues that arise from the Ministerial Review during the later stages of the projects.

Glossary of abbreviations and terms

Commission	Electricity Commission
Minister	Minister of Energy and Resources
Act	Electricity Act 1992
Rules	Electricity Governance Rules 2003
Regulations	Electricity Governance Regulations 2003
VoLL	Value of lost load – i.e. cost to users from forced power cuts

Contents

Executive summary **A**

Glossary of abbreviations and terms **E**

1. Introduction and purpose of this paper **3**

1.1 Introduction 3
1.2 Invitation to conference 4
1.3 Purpose of this paper 4
1.4 Submissions 5

2. Background **6**

2.1 Concerns with current arrangements 6
2.2 Underlying problem 7
2.3 Options to address underlying problem 11

3. Scarcity pricing/compensation mechanisms **13**

3.1 Introduction 13
3.2 Spot price formation during market distress 13
3.3 Effect on market risk and competition 15
3.4 Prudential and retail market arrangements 16
3.5 Compensation during conservation campaigns 16
3.6 Reserve Energy Scheme 19

4. Compulsory contracting mechanisms **21**

5. Assessment of options **23**

5.1 Relative merits of options 23
5.2 Possible pathways for adopting scarcity pricing 28

6. Next steps **31**

7. Summary of questions **35**

Appendix 1 Format for submissions **39**

Appendix 2 Scarcity Pricing Mechanisms **41**

Appendix 3 Default buyback mechanism **53**

Appendix 4	**Compulsory contracting arrangements**	**56**
Appendix 5	**Scarcity pricing and investment incentives**	**63**

1. Introduction and purpose of this paper

1.1 Introduction

1.1.1 The Electricity Commission has launched a Market Development Programme (MDP) to improve the performance of the electricity market. The MDP is designed to address two key areas of concern:

(a) **supply security** – although actual power cuts due to insufficient generation have not occurred in New Zealand since the 1970s, there is a strong perception that the system is unreliable. The succession of supply 'scares' and frequent calls for widespread voluntary power savings (three times since 2001) reinforce this perception. There is also doubt about whether current arrangements provide sufficient reward for resources (generation and/or demand-side response) which are required very infrequently to meet peak demand, or to offset low hydro generation during extreme droughts; and

(b) **electricity prices** - prices have increased for all customer groups, but have risen especially sharply for residential users. There is uncertainty over whether the increases reflect rising costs, poor efficiency or the exercise of market power.

1.1.2 Because of the complex and interlinked nature of the electricity supply chain, the MDP is being taken forward as an integrated package of measures. Consultation papers on individual measures within the MDP will be released progressively from late September 2009 through to October 2009. A more detailed timeline on the release of the MDP consultation papers is provided on the Commission's website: http://www.electricitycommission.govt.nz/opdev/workcal/?searchterm=calendar.

1.1.3 This paper describes a major element of the MDP, which is the possible introduction of scarcity pricing or compulsory contracting mechanisms (the latter is also referred to as 'capacity mechanisms'). These approaches are intended to improve security by increasing the expected reward for providers of generation/demand response during periods of tight supply.

1.1.4 Two other consultation papers on related issues are being released alongside this paper. They are:

(a) Options for locational hedging arrangements;

(b) Options for transmission pricing

1.1.5 While all three consultation papers are 'stand-alone' documents, the Commission recognises the strong linkages between the topics that they cover. For this reason, the papers have been released as a suite, with a common timetable allowed for submissions.

(i) The Commission is mindful that these papers are being released whilst there is an on-going Ministerial review of the electricity market.

(ii) The Ministerial review discussion paper: *Improving Electricity Market Performance* made a number of recommendations that align with the MDP initiatives and recognised that the Commission has a review of transmission pricing underway. Interested parties have made submissions in response to this discussion paper.

(iii) All three of the Commission's consultation papers present high-level options rather than proposing a preferred solution and as such there will be time to consider issues that arise from the Ministerial Review during later stages of these three – and other MDP – projects where the options are being refined.

1.2 Invitation to conference

1.2.1 The Commission invites interested parties to a conference to be held at Wellington 29 October 2009. This one-day conference will cover the three consultation papers outlined above as well as dispatchable demand options. This conference is intended to assist interested parties in considering the consultation papers with a view to making submissions.

1.2.2 Details on this conference and on how to register will be made available on the Commission's website, http://www.electricitycommission.govt.nz/opdev/mdp .

1.3 Purpose of this paper

1.3.1 This paper discusses a number of broad alternative approaches that are intended to improve security of supply.

1.3.2 The paper describes each of the broad alternative mechanisms, and uses examples to explain how they could operate in practice. It is important to stress that the examples are included for illustrative purposes, and should not be treated as definitive designs. Indeed, the Commission recognises that a significant amount of detailed work and refinement would be required before either option could be brought to implementation.

1.3.3 At this stage of the process, the Commission is evaluating the broad alternatives, with the aim of selecting the most attractive option for in depth consideration. This option would be developed in detailed form, and the costs and benefits would be evaluated against the status quo. The Commission would expect to release a consultation paper on that option and associated assessment of relative merits in early 2010.

1.3.4 In the meantime, the Commission invites feedback on the high level issues canvassed in this paper, and the proposed path for moving forward.

1.4 Submissions

The Commission's preference is to receive submissions in electronic format (Microsoft Word). It is not necessary to send hard copies of submissions to the Commission, unless it is not possible to do so electronically. Submissions in electronic form should be emailed to submissions@electricitycommission.govt.nz with Consultation Paper—Scarcity Pricing and Compulsory Contracting Mechanisms in the subject line.

If submitters do not wish to send their submission electronically, they should post one hard copy of their submission to the address below.

Kate Hudson
Electricity Commission
PO Box 10041
Wellington 6143

Kate Hudson
Electricity Commission
Level 7, ASB Bank Tower
2 Hunter Street
Wellington

Tel: 0-4-460 8860

Fax: 0-4-460 8879

1.4.1 Submissions should be received by 5pm on 7 December 2009. Please note that late submissions are unlikely to be considered.

1.4.2 The Commission will acknowledge receipt of all submissions electronically. Please contact Kate Hudson if you do not receive electronic acknowledgement of your submission within two business days.

1.4.3 If possible, submissions should be provided in the format shown in Appendix 1. Your submission is likely to be made available to the general public on the Commission's website. Submitters should indicate any documents attached, in support of the submission, in a covering letter and clearly indicate any information that is provided to the Commission on a confidential basis. However, all information provided to the Commission is subject to the Official Information Act 1982.

2. Background

2.1 Concerns with current arrangements

2.1.1 The principal security[2] challenge in New Zealand has been 'dry year' risk (also referred to as 'energy adequacy'). Our system relies to a large extent on hydro generation, but has very limited hydro storage. The security issue therefore revolves around the management of energy resources (hydro storage, gas, coal etc) and demand over the weeks or months when there is a prolonged and severe drought.

2.1.2 There are concerns in the following areas:

(a) when a dry year occurs, parties exposed to high spot prices (i.e. under-hedged industrial users and suppliers with insufficient hedges/generation) tend to lobby for public conservation campaigns. Power conservation imposes real costs on affected businesses and consumers, and fosters a perception of fragile security, undermining New Zealand's investment reputation. The frequent use of conservation campaigns (2001, 2003 and 2008 and a 'near miss' in 2006) suggests over-reliance on this tool, and undermines confidence in the electricity system;

(b) governments naturally become concerned when security of supply is threatened, and can face strong pressures to intervene. Participants can have difficulty predicting the nature of such intervention, and may therefore delay or avoid taking appropriate actions (e.g. demand buy-backs). This can lead to an unfortunate circle of participant inaction, increased government concern, and so on. To counter this risk, it is desirable to strengthen the level of government (and public) confidence in security arrangements. This in turn should reduce participants' concern about the potential for unpredictable intervention;

(c) as hydro conditions deteriorate, thermal generation is expected to ramp up to reduce pressure on hydro storage. While this general pattern has been evident in dry periods, during the 2008 drought there were periods when thermal generation wasn't running at full capacity and hydro generators preferred to drawdown discretionary storage. This occurred even though the assessed likelihood of subsequent shortage was significantly greater than 1 in 60, which is the security standard sought by the government;

(d) discretionary demand reductions are a valuable source of flexibility to address dry year risk. However, aside from demand cuts by industrial and commercial users exposed to spot prices (and public conservation campaigns noted earlier), there has been little evidence of active demand

[2] This paper focuses on security issues at the wholesale level. The level of security experienced by end-use customers is also affected by the performance of transmission and distribution networks. Consideration of network performance issues lies outside the scope of this paper.

response initiatives. Indeed, for residential and commercial customers, the provision of incentive-based arrangements appears to have lessened over time. For example, in 2001 Mercury offered rebates to residential customers who saved power. In 2001 and 2003, other major retailers made donations to community causes based on the level of demand savings that were achieved. No similar arrangements to mass market customers were offered in 2008;

(e) generation plant that is used to provide dry year cover struggles to earn sufficient revenues to justify its retention. This is illustrated by Contact's decision in the late 1990s to sell the gas turbines at Stratford and Whirinaki, the progressive closure of New Plymouth power station, and the recent statements by Genesis regarding the potential for reducing generation capability at Huntly[3].

2.1.3 While dry year risk has been the principal security challenge, the ability to meet demand during short periods of system stress (referred to as 'capacity adequacy') is also important. Indeed, until the planned upgrade of the HVDC link between the North and South Islands is available around 2012, capacity adequacy in the North Island is expected to be relatively tight.

2.1.4 There has also been increasing concern about whether there is sufficient incentive to invest in resources (supply or demand response capability) to meet peak demand, and/or provide fast start capability when there is a sudden and unexpected reduction of generation from intermittent sources (e.g. wind).

Q1	What concerns do you have with regard to security of supply under existing arrangements?

2.2 Underlying problem

2.2.1 The concerns described above are symptoms caused by a common underlying problem, which is that market participants can shift the costs of some actions onto others.

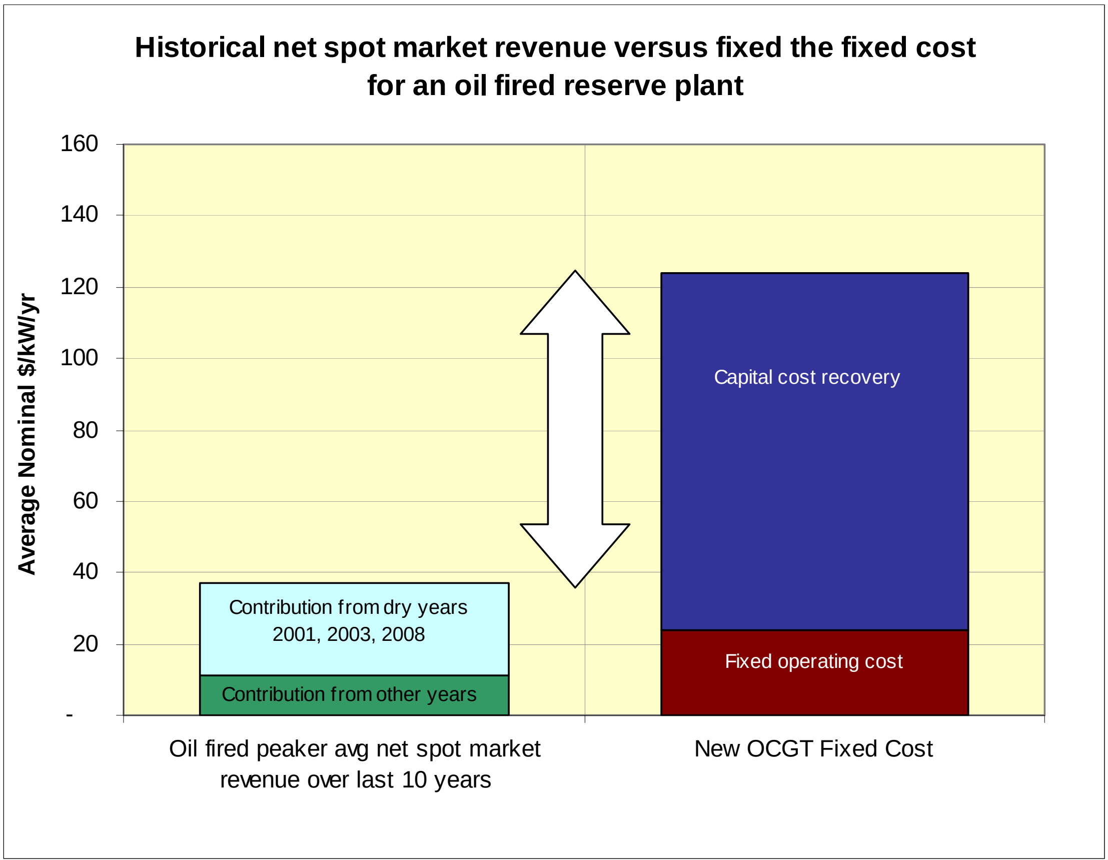
2.2.2 This ability to shift costs encourages over-use of some tools (e.g. conservation campaigns) because the perceived cost to the parties seeking to trigger their use is lower than their overall cost to New Zealand.

2.2.3 Meanwhile, other options with a lower overall cost (e.g. thermal generation to cover dry-year risk) may struggle to earn sufficient revenue, because the 'natural' customers for such resources (e.g. hydro generators) are incentivised to rely on tools where there is more scope for cost shifting. This inability to earn sufficient revenue to justify 'security' investments is sometimes referred to as the 'missing money' problem.

[3] For example, see Genesis submission on the Emissions Trading Scheme, February 2009

2.2.4 Analysis of historic spot prices tends to support the view that there is a missing money problem. Figure 1 shows the annual revenue required to justify investment in an oil-fired open cycle gas turbine (OCGT), and the net revenue available from the spot market for plants with different variable operating costs over the period 2000-2009[4]. The net revenue contribution has been split between 'dry years' and other years. This provides a *first order approximation* of the contributions to fixed costs that such a plant would have received over the period from the provision of *energy* capability to meet dry year requirements and *capacity* to meet peak demand or other short term requirements.

Figure 1 – Historical net spot market revenue versus fixed cost for an oil fired plant



2.2.5 The average net spot market revenue for an oil fired peaker over the period 2000-2009 was only around $40/kW/yr, significantly below the level needed to justify investment in *new* oil fired reserve plant.

---

4 The plant may recover its revenue directly from the spot market, or from contracts which insure buyers against high spot prices. In both cases, unless spot prices can reach necessary levels, the plant will be uneconomic. The data for the oil fired peaker is based on an OCGT with annualised capital costs of $100/kW/year and fixed operating costs of $24/kW/year including fuel management. Variable operating costs are driven by oil prices, and these vary through time but average approximately $200/MWh. Variable operating costs have been deducted from actual observed nominal spot market prices. These figures are subject to estimation uncertainty, and the analysis should be treated as indicative..

2.2.6 As discussed in the Market Design Report[5] the fact that historic New Zealand spot prices were insufficient to underpin investment in pure peaking or reserve energy plant does not by itself indicate there is a problem with investment incentives. It is possible[6] that such plant was not required in the period, either because there was adequate overall capacity or because the need was for more mid-merit order or base load plant. Historic analysis is also complicated by the fact that fuel costs have changed over time, meaning that historic spot price levels may not be representative of future trends. Furthermore, the analysis does not include the value of any revenue stream outside the spot market, such as payments[7] for provision of ancillary services, nor does it factor in the risk and cost of more extreme spot market outcomes that have not been observed in the historical period.

2.2.7 It is more difficult to assess the historical net spot market returns available to other forms of gas/coal fired dry-year firming plant as it is difficult to estimate the cost of providing reliable but variable fuel supply (e.g. coal stockpiling, gas supply flex and transport capability). If the cost of flexible fuel supply was 50% higher than base load then a gas/coal reserve plant would have received an average net spot market return of \$120 to \$170/kW/yr over the last 10 years. This is still short of the fixed cost of new gas/coal fired reserve capacity, but would generally be considered adequate to justify retaining modern dry-year firming plant[8] but may not be adequate to justify retaining some of our existing older reserve plant.

2.2.8 Despite the limitations of this historical analysis, the very large gap between historical spot market net revenues and those required to justify new investment, coupled with the progressive decommissioning of older reserve plant[9], suggests that there may be a problem with investment signals for reserve energy plant. This potential problem is likely to become more significant in the future as more intermittent generation is added to the system and as gas supply becomes less flexible.

2.2.9 As noted earlier, the ability to shift costs will tend to suppress spot prices during periods of market distress or scarcity. Areas where cost-shifting can occur include:

(a) parties selling to mass-market customers with insufficient hedge contracts or generation to cover their spot market purchases[10] can gain a significant

[5] See Electricity Commission "Market Design Review – Options Paper 8 July 2008, page 5-112"

[6] Note that the Electricity Commission reviewed the need for additional reserve energy plant each year from 2004 and in each case determined that no additional reserve plant was required to meet the standard.

[7] Or avoided costs for a portfolio generator.

[8] To justify the retention of existing reserve plant, the net market returns need to exceed the fixed operating and maintenance costs. While the fixed operating cost for new hydro-firming coal/gas fired plant is typically around \$35-70/kW/yr, the fixed cost of retaining existing old plant may be higher. For example PB Power suggest that the fixed O&M cost for Huntly units is \$70/kW/yr ("Thermal Power Station Advice - Fixed & Variable O&M Costs", Sep 2009).

[9] For example, the original stations at Stratford and Whirinaki, Otahuhu A, New Plymouth power station.

[10] These could be wholesale buyers that aren't fully hedged, or generators that have sold more output on fixed price contracts than they can reliably produce.

benefit from public conservation campaigns. For example, a large generator-retailer could save around $600,000/day[11], but most of the cost would be borne by the electricity users who experience disruption and inconvenience, or more widely through lower confidence in supply security;

(b) under the reserve energy scheme, some of the costs for the Whirinaki plant are recovered from all wholesale purchasers, whereas most of the benefit of operation is captured by parties who are net buyers in the spot market[12];

(c) if security standards are relaxed by not maintaining instantaneous reserves at full levels, electricity users are exposed to increased risk of widespread power cuts if a generator or transmission circuit trips. Under present arrangements, this risk is not reflected into spot prices when security standards are relaxed. This means that net buyers in the spot market benefit (through lower prices), but the cost is borne by consumers (who face a higher risk of being automatically tripped in a contingency); and

(d) if forced power cuts were ever required (they haven't been since the market was established), under-hedged buyers and over-sold generators would benefit, but the costs (extreme in this case) would be borne by the electricity users who are forcibly turned off.

2.2.10 Under the current framework, the main tool to address security problems is the Reserve Energy scheme. This scheme requires the Commission to procure additional generation or demand response resources if assessed security falls below a pre-defined standard.

2.2.11 However, this mechanism can itself have the unintended effect of aggravating the so-called 'missing money' problem. This arises because unlike market-based alternatives, Reserve Energy resources are not dependent on the spot and contracts markets for all their revenues. This can undercut the revenue for market-based provision of peaking/firming plant and demand response resources. This can further increase the need for Reserve Energy procurement, and so forth.

2.2.12 Ultimately, there is a risk that the reserve energy scheme becomes the primary means of paying for all infrequently used plant, and possibly for all new supply. At that point, the scheme is unlikely to be sustainable because it is no longer a 'back stop' as originally intended.

Q2	What, if any, other underlying issues lead to the potential for cost shifting among market participants?

---

11 Assuming the generator-retailer was generating 8,000 MWh/day, purchasing 10,000MWh/day from the wholesale market, demand reduced by 10% and that spot prices were reduced from $500/MWh to $400/MWh.

12 It could be argued that *all* electricity buyers benefit because the *existence* of the Whirinaki plant lowers expected spot prices. However, this benefit would only occur if the reserve energy scheme results in more plant being on the system than would otherwise be the case. It is likely that investors in 'market' plant take the Reserve Scheme into account, and adjust their investment plans, resulting in no overall change to security.

2.3 Options to address underlying problem

2.3.1 There are two broad options to address the problem discussed above:

(a) scarcity pricing/compensation mechanisms – these seek to address the opportunities for cost shifting, to reduce parties' incentives to rely on options that transfer costs onto others; or

(b) compulsory contracting mechanisms – these seek to directly constrain wholesale participants' behaviour, by limiting the range of choices they can make regarding security.

2.3.2 These broad options are described in the following sections. They focus on the high level issues, because these provide the main basis for judging the likely outcomes and risks of the different options, and identifying a preferred path for moving forward. That said, distinguishing between high level and detailed issues is necessarily subjective. For this reason, further detail on each of the broad options is provided in Appendices.

3. Scarcity pricing/compensation mechanisms

3.1 Introduction

3.1.1 This option preserves market participants’ discretion over generation, usage and hedging decisions, but aims to improve the incentives during periods of market distress by reducing the scope for cost shifting. The changes fall into the following areas:

(a) spot price formation during market distress;

(b) compensation during public conservation campaigns; and

(c) future of Reserve Energy scheme.

3.1.2 In addition, with sharper price signals during times of market scarcity, it would be important to consider the adequacy of prudential arrangements and the effect on the potential exercise of market power/price volatility.

3.1.3 Each of these issues is discussed below.

3.2 Spot price formation during market distress

3.2.1 As supply becomes increasingly tight, more expensive generation sources are called upon to satisfy demand, causing the spot price to rise. Once all offered generation is dispatched (and price-based demand response has occurred), the only remaining tools are relaxing security standards (by carrying insufficient instantaneous reserves) or forcibly cutting demand. These actions occur through administrative mechanisms, with no explicit price signal reflected into the spot market, even though the actions impose costs or risks on electricity users.

3.2.2 Furthermore, if these administrative mechanisms are used, spot prices may in fact decline because the pricing algorithm works on metered demand, which will be lower than unsuppressed demand.

3.2.3 To address these issues, various forms of ‘scarcity pricing’ could be applied when administered actions[13] occur in the spot market. These scarcity prices can be thought of as surrogate demand-side bids to reflect the costs that electricity users would bear if the administered actions are applied. A number of overseas jurisdictions use mechanisms of this nature including the National Electricity Market in Australia, Nord Pool in Scandinavia and Northern Germany, the Single Electricity Market in Ireland and ERCOT in Texas.

3.2.4 The main situations where scarcity pricing might be considered for New Zealand are depicted in Table 1. To provide some guidance on the possible level of

---

[13] Administered in this context refers to actions by the Electricity Commission or the system operator, rather than by market participants in response to price signals.

default prices in each situation, *indicative* estimates are provided of the costs borne by electricity users. These estimates are provided for illustrative purposes only, and would need to be refined through detailed analysis if any of the options were implemented in practice.

Table 1 – Possible situations where scarcity prices might be applied

	Pre-shortage	**Actual shortage**
Dry-year energy adequacy	Instigation of conservation campaign ~$500-600/MWh Cost expected to be higher than SRMC of oil-fired plant[14], but significantly below value of lost load (VOLL)	Rolling power cuts ~$2,500 - 5,000/MWh Cost based on VOLL, adjusted for fact that outage would occur with prior notice of hours or days
Real time capacity adequacy	Shortfall of instantaneous reserves Cost based on probability of forced load curtailment (in turn based on extent of reserves shortfall) x VOLL	Demand allocation notices issued by System Operator $10,000 - 20,000/MWh Cost reflects VOLL without prior notice

3.2.5 The table provides a high level summary of the scarcity pricing options. A wide range of sub-options exist, particularly in relation to the mechanics of how default prices might apply. Decisions would be required on issues such as:

(a) whether default prices set a price floor, or represent a fixed level;

(b) whether the default price mechanism affects generation dispatch patterns and nodal price differentials; and

(c) the specific form of any trigger conditions, and any exceptions that apply to these triggers.

3.2.6 While these are important matters, the Commission sees them as subsidiary to the main question of whether to adopt scarcity pricing for any of the situations

[14] Since response that is cheaper (e.g. pre-contracted hot water heating cuts or voluntary reductions in non essential or discretionary use) will occur at an earlier point.

described above. For this reason, they are not considered further in detail in this section, but are canvassed in Appendix 1.

3.2.7 In the Commission's view, the decision on whether to adopt scarcity pricing would turn on a range of broader considerations discussed in the following sections.

3.3 Effect on market risk and competition

3.3.1 While scarcity pricing should ensure that spot prices more accurately reflect the value of electricity (i.e. lost load) in a situation of market distress, participants are likely to be concerned about increased price volatility. To a degree, this concern is inevitable, as the prospect of high spot prices provides the driver for increased hedging, and the revenue base to support peaking/reserve generation plant and voluntary demand response.

3.3.2 However, it is also important to ensure that wholesale price risks do not become unmanageable (or be perceived as such) by market participants. It this context, legitimate concern is likely to focus on three issues:

(a) Potential for exercise of market power, leading to contrived rather than genuine scarcity;

(b) Scope for unintended outcomes (e.g. mis-specification of the scheduling, pricing and dispatch model or parameters); and

(c) Treatment of very extreme events, for example a major earthquake on the alpine fault which knocked out much of New Zealand's generation capacity.

3.3.3 Concern about these sorts of issues have arisen in other markets and have been dealt with in a number of ways. These include:

(a) Measures to facilitate wholesale market competition, hedging instruments and hedge market depth;

(b) Measures to improve demand side participation;

(c) Increased market monitoring to detect and deter any undue exercise of market power;

(d) Tight specification of pricing rules and algorithms, and the manner for exercising any discretions by market operators;

(e) Measures to improve market participants' ability to predict extreme prices, allowing them to take pre-emptive action;

(f) Provisions that allow for market suspension in 'extreme' events; and

(g) Limitations on the application of scarcity pricing.

3.3.4 Each of these is discussed more fully in Appendix 2, section 2.7. In short, the Commission does not believe that scarcity pricing could be introduced on a 'stand-alone' basis. It would need to be accompanied by other measures to ensure that market risk does not become unmanageable (or be perceived as such). This scope and depth of these ‘companion’ measures could differ depending on the form of scarcity pricing that might be adopted. This issue is discussed later in this paper.

3.4 Prudential and retail market arrangements

3.4.1 It would be important to ensure that there is no undue risk of default by market participants. Current prudential arrangements may be sufficient to ensure this, but it would be useful to review the arrangements to ensure this the case.

3.4.2 In particular, the review should look at the extent to which risk assessment is forward-looking, since this is the key issue in a dry-year context. The review should also consider whether there are mechanisms that would make it easier for parties to utilise hedge contracts as security for their forward purchases, as this will be an important issue for independent retailers.

3.4.3 Looking downstream of the spot market, there is a case for improved disclosure of *aggregate* risk positions by sellers of hedge contracts. At the very least, there is a case to consider disclosure of overall positions to the prudential manager (to ensure they have a proper picture of risk), but there is also merit in considering greater public disclosure, along the lines of the continuous disclosure regime for the New Zealand Stock Exchange.

3.4.4 At the retail level, the main risk is that retailers seek to offload spot price risk by terminating contracts, or other inappropriate measures to shed load during a period of market distress. Current arrangements may be sufficient to address this issue, but again it would be important to review them to ensure their robustness.

3.5 Compensation during conservation campaigns

3.5.1 As noted earlier, generator-retailers exposed to high spot prices can have a strong incentive to lobby for public conservation campaigns during a dry year. Affected generator-retailers benefit through:

(a) purchasing smaller volumes of electricity at high spot prices to meet their end-use customers’ demand; and

(b) lowering their average purchase cost because spot prices are reduced.

3.5.2 Applying a default scarcity price during public conservation campaigns would address issue (b), but retailers would still have a strong incentive to call for campaigns, whether or not they are hedged. This arises because most domestic and small commercial users are supplied on fixed price, *variable volume* tariff contracts. As a result, retailers benefit strongly when spot prices are high and these customers reduce their demand[15].

3.5.3 To remove the 'windfall' gain arising from public conservation campaigns, retailers could be required to pay customers for their power savings – in effect this would be a default buy-back arrangement. Ideally, the payment to each customer would reflect their individual volume of savings during the relevant period, and the level of spot prices in the absence of a public conservation campaign[16]. In practice, this would be administratively difficult to achieve because meter reading frequency is not sufficient to track individual customer demand over short periods[17], and it is not possible to observe the level of spot prices in the in absence of public conservation.

3.5.4 Furthermore, the primary objective in this context is to reduce the incentive on retailers to lobby for, and over use, public conservation campaigns. This could be achieved through a less complex compensation regime based on average levels of savings and spot prices. In its most simple form, this could be a flat payment of (say) $10-12/week[18] per customer applied for the duration of any public conservation campaign.

3.5.5 To provide scope for innovation, the default arrangement could be waived where retailers and customers already had contracts in place that reward conservation efforts. While this is a desirable design feature, it would be important to consider the specific forms of contract that would qualify for exemption. For example, contracts that passed through all spot price risk are unlikely to be suitable for residential users. On the other hand, a contract that shared the benefit of demand savings between the end-user and the retailer might be acceptable. Careful consideration would be required in this area.

3.5.6 The nature of the interaction between scarcity pricing and a default buyback mechanism is shown in Figure 2. It shows the savings to a generator-retailer from the instigation of a public conservation campaign under different policy regimes[19]. As noted earlier, under present arrangements a large retailer can

---

[15] In theory customers on these tariffs do not have an individual financial incentive to reduce consumption during these campaigns, however experience has shown that they do respond in the public interest. This does not apply to large users because their contracts are generally for a defined volume. The customer can therefore benefit from conservation efforts, by selling back some of this volume to their retailer or via hedge settlements.

[16] Strictly speaking, the customer should pay the retailer the implied variable *energy* price in the retail tariff so it takes ownership of that energy, and then sell it back to the retailer. The buyback price for this energy can be expected to lie between the spot price in the absence of a public conservation campaign (since the retailer wouldn't rationally pay more than this) and the cost to the customer from foregoing supply. Unfortunately, neither of these figures is observable in practice.

[17] Most meters are read on monthly or bi-monthly cycles. The growing use of smart meters will facilitate measurement of demand over much shorter periods.

[18] This is included for illustrative purposes. It is based on an average usage of around 900 kWh/month, a spot price of $500-600/MWh and 10% savings.

[19] This simplified example is included for illustrative purposes. The common assumptions are retail load of 10,000 MWh/day before savings, generation of either 8,000 MWh/day (20% unhedged) or 10,000 MWh/day and 10% load savings when a public campaign is running. Market prices without savings are assumed to be $500/MWh, falling to $400/MWh if a public conservation campaign is operating. To avoid the example

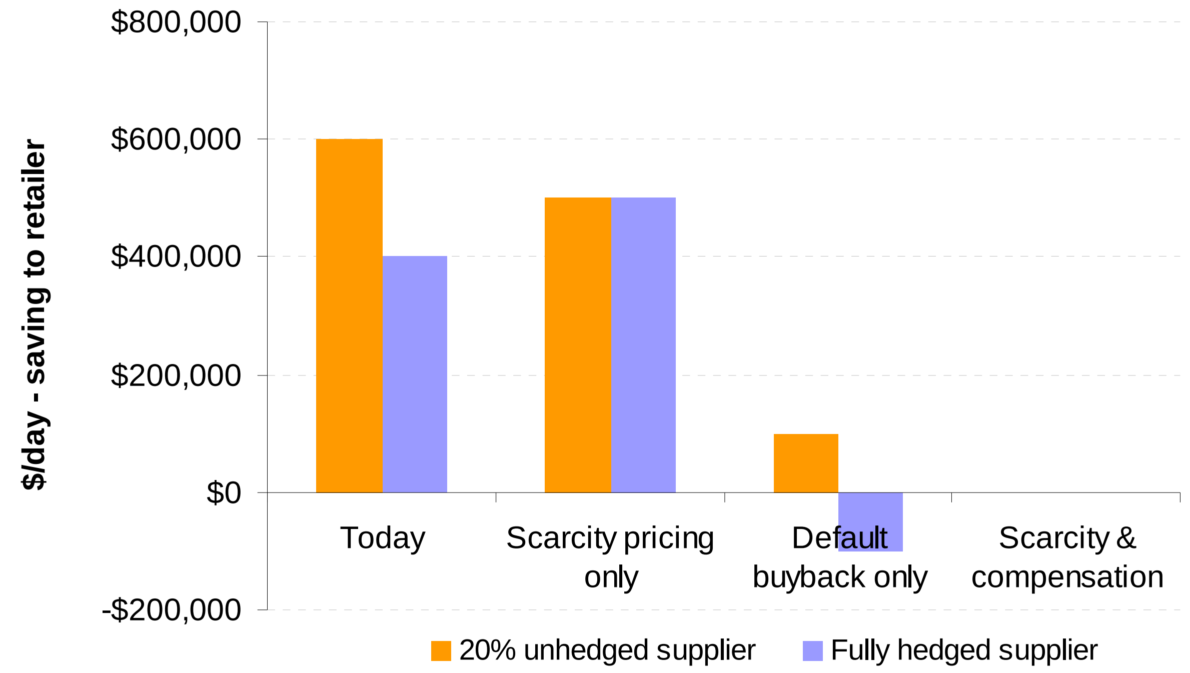
gain significant benefits from public conservation measures. Note that these benefits would be lower for a fully hedged generator-retailer, but can still be significant. Put another way, under current arrangements, there is an incentive for generator-retailers to be under-hedged relative to expected retail demand.

3.5.7 Adopting a scarcity pricing regime would address the incentive to be less than fully hedged. As shown in the chart, the fully hedged generator-retailer and supplier with 20% spot exposure would have the same incentives as regards calling for a public conservation campaign. However, there would still be a substantial saving available to them from such a campaign in this example.

3.5.8 Likewise, while the application of a default buy-back mechanism alone would significantly reduce the incentive to call for public conservation campaigns, the incentive to be less than fully hedged would remain.

3.5.9 In short, it requires the combination of the two mechanisms because there are two separate issues – the incentive to under-hedge, and the incentive to shift costs onto consumers through public conservation campaigns.

Figure 2 – Cost saving/shifting from a public conservation campaign



3.5.10 Further information on the design of a default buyback arrangement is set out in Appendix 3.

---

becoming overly complex, no account is taken of any margin between the end-user tariff and generator-retailer's operating costs..

3.6 Reserve Energy Scheme

3.6.1 As noted above, the Reserve Energy scheme (and the Whirinaki plant within it) is intended to provide a backstop in the event that market arrangements don't provide sufficient security. However, experience in the winter of 2008 shows this has been problematic. Participants are likely to factor the scheme into their plans, meaning that it is questionable whether the scheme lifts overall security in the intended manner.

3.6.2 Furthermore, the scheme can have the unintended effect of reducing the incentive on parties to prudently manage their risks. This arises because a wholesale purchaser with an unhedged position gets more benefit from Whirinaki's operation than one which is fully hedged[20], yet both pay the same contribution to the plant's costs through the levy. At the margin, this reduces parties' incentive to hedge, build plant or enter into firm demand response arrangements.

3.6.3 The current form of the scheme also fits awkwardly with the Commission's role as a regulatory body.

3.6.4 The Commission does not have the legal power to significantly modify the Reserve Energy scheme as it would require changes to existing legislation. However, the effects of the scheme have been noted in the Ministerial Review of Electricity Market Performance[21], and the Government has signalled a willingness to consider changes to the scheme.

3.6.5 For these reasons, the Commission believes it is likely that the Reserve Energy scheme will be modified with the aim of transitioning to more market-based set of arrangements.

3.6.6 In the meantime, the Commission is looking at options to improve the effectiveness of the Reserve Energy scheme.

[20] In this example, the hedged party is indifferent to whether Whirinaki runs (because it is fully hedged) whereas the unhedged party would benefit to the extent that spot prices are reduced. It might be argued that the hedged party also benefits from the presence of Whirinaki when negotiating its hedge contract. This is correct provided the presence of Whirinaki does not alter the investment or operating decisions of other parties. However, this appears unlikely to be the case, as market participants are likely adjust their actions, relative to a situation where the system had no Whirinaki station.

[21] See http://www.med.govt.nz/templates/MultipageDocumentTOC____41697.aspx for more information.

4. Compulsory contracting mechanisms

4.1.1 The Reserve Energy scheme seeks to address security concerns through the provision of information and the ability to top-up the market with reserve energy if required. It is inherently difficult for the scheme to 'ensure' security since it controls only a very small proportion of total capacity, whereas actual security depends on the behaviour of all generators and wholesale buyers.

4.1.2 A compulsory contracting mechanism would go further than the Reserve Energy scheme by imposing obligations on *all wholesale market buyers (retailers and relevant industrial users) and generators:*

(a) wholesale market buyers would be required to hold contracts or firm generation capacity to meet a pre-determined minimum energy or capacity security standard; and

(b) generators would be limited in their ability to sell firm contracts for energy or capacity (to ensure they are not over-committed).

4.1.3 A number of compulsory contracting schemes have been adopted internationally to ensure adequate generation capacity. By nature, these schemes are relatively complex and prescriptive, requiring detailed rules covering matters such as:

(a) the nature and level of obligation – for example capacity and/or energy, the amount of cover required;

(b) the method for determining the level of aggregate forecast load growth, and apportioning this among wholesale buyers;

(c) the method for rating individual generators as to their firm energy/capacity capability, taking into account hydrology, wind patterns, thermal fuel risks, plant reliability, supply diversity etc;

(d) arrangements to allow demand side participants to opt out to the extent that they have 'firm' demand response capability;

(e) arrangements for monitoring and enforcing obligations, including penalties for non-compliance, and

(f) arrangements for trading of capacity/energy obligations to deal with plant outages, delays in commissioning new plant and changing retailer market shares etc.

4.1.4 These issues are described further in Appendix 4.

4.1.5 The operation of these schemes overseas has been challenging, even in 'simple' systems that are predominantly thermal with an unconstrained fuel supply and transmission networks.

4.1.6 New Zealand's physical issues would make a scheme more complex in some respects. In particular, most overseas schemes focus on ensuring sufficient capacity to meet peak demand. In New Zealand, the scheme would also need to ensure dry-year energy adequacy. This would require rolling assessments of the ability to withstand a severe drought over the coming months.

4.1.7 This is a more complex matter than assessing the system's ability to meet instantaneous peak demand, as assumptions need to be made about the future management of hydro storage lakes and thermal fuel stocks. Indeed, the only scheme that has been identified that formally addresses energy adequacy is the Colombian Firm Energy Market which was introduced in 2006.

4.1.8 The other specific challenge in the New Zealand context is the need to account for transmission constraints. While new transmission capacity currently under development will largely resolve current grid constraints, some new constraints can be expected to occur from time to time in an efficient electricity market. These would complicate the task of determining the level of 'firm' supply attributable to each generator.

4.1.9 These issues and complexities mean that the scheme would create significant administration costs for the Commission and compliance costs for market participants.

4.1.10 A compulsory contracting arrangement could limit the exercise of market power in the spot market by ensuring a high level of contracting. However it would still be susceptible to the exercise of market power in the contracts market. This might need to be addressed through other mechanisms, or by extending the obligation period over a number of years so that new entrant investors can compete with incumbents.

4.1.11 The other key issue with these schemes is that they necessarily limit some commercial choices because rules would need to prescribe the range of parties' decisions. This is likely to reduce dynamic efficiency, for example by encouraging over-build or distorting the generation mix resulting in higher overall costs of supply.

4.1.12 While all of these issues would need to be considered, a compulsory contracting regime should be able to ensure adequate funding for the volume of generation/ demand response necessary to meet the desired security standard. It should also ensure that the required standard will be met, provided the timeframes of the obligations are sufficiently long, and there is effective monitoring and enforcement

5. Assessment of options

This section looks at the relative merits of the different options, and sets out a proposed path for moving forward.

5.1 Relative merits of options

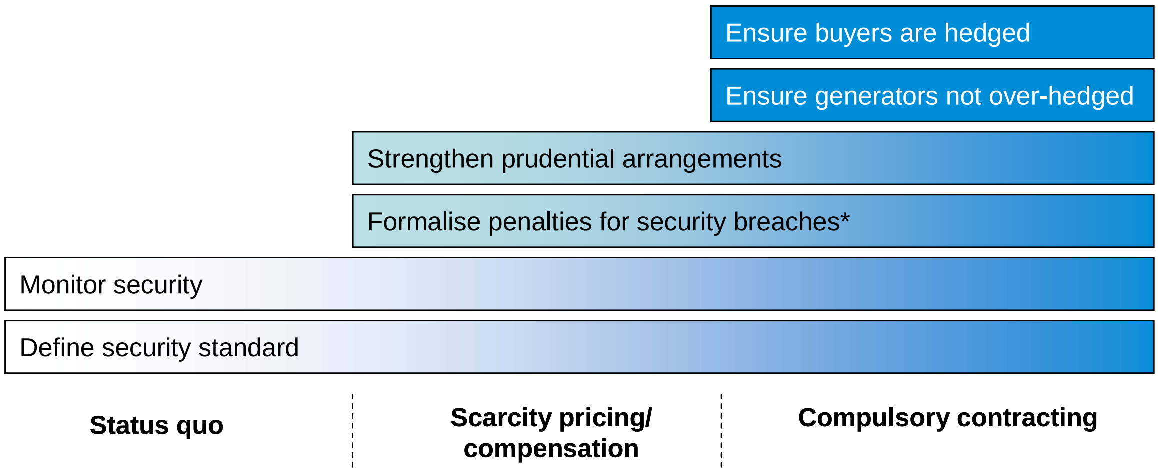
5.1.1 There are two main alternatives to the status quo:

(a) adopt a scarcity/compensation arrangement; or

(b) adopt compulsory contracting approach.

5.1.2 Figure 3 shows each option in terms of its key building blocks.

Figure 3 – Core building blocks of different approaches



* Via prices/compensation in scarcity model, and penalties in the compulsory contracting mechanism

5.1.3 The main difference between the status quo and the scarcity/compensation approach lies in the incentive arrangements during any periods of market distress. If these were sharpened (e.g. through scarcity pricing, default buybacks for mass market customers during public conservation campaigns, changes to the Reserve Energy scheme), there would be a consequential need to review prudential arrangements.

5.1.4 If compulsory contracting were introduced, two further building blocks would be required – namely a means to ensure buyers are fully hedged, and procedures to make sure generators limit their hedge sales to no more than firm output.

5.1.5 The differences in component building blocks are important in considering the relative strengths and weaknesses of the main options.

5.1.6 Table 2 provides a high level assessment of the relative merits of the alternatives, using the outcomes that the Commission must seek to achieve under section 172N of the Electricity Act as the reference point. The table also comments on the relative implementation ease, transition issues, and key risks of each option.

Table 2 – Relative merits of the main alternatives to the status quo

	Scarcity/compensation	Compulsory contracting scheme
172N 2(a) Energy and other resources are used efficiently	Improve incentives for voluntary response, and for retailers to offer innovative incentive based tariffs and contracts.	Incentives for demand-response can be included in scheme, but add complexity and may be somewhat inflexible to ensure compliance with overall security objective
172N 2(b) Risks (including price risks) relating to security of supply are properly and efficiently managed	Provides stronger market incentive for parties to manage security risks	Provides high degree of confidence around security - compulsory contracting ensures security standards are met without relying on market incentives alone
172N 2(c) Barriers to competition in the electricity industry are minimised for the long-term benefit of end-users	Greater wholesale price risk may increase barriers for new entrant retailers and for non-portfolio generators	Administrative requirements and compliance regimes may create additional barriers New generation investment may be able to compete more easily if contract timeframe sufficient to support new entrants (2+ years)
172N 2(d) Incentives for investment in generation, transmission, lines, energy efficiency, and demand-side management are maintained or enhanced and do not discriminate between public and private investment	Sharper incentives on parties should provide revenue base to underwrite reserve/peaking plant and demand response	Scheme provides high degree of revenue assurance for reserve/peaking plant.
172N 2(e) The full costs of producing and transporting each additional unit of electricity are signalled	Scheme would help to ensure cost is signalled	Scheme could help to ensure cost is signalled, depending on form of penalty regime

	Scarcity/compensation	Compulsory contracting scheme
172N 2(f) Delivered electricity costs and prices are subject to sustained downward pressure	While scarcity pricing is intended to alter the *shape* of spot prices rather than the *average* level, it might put upward pressure on average spot prices Scarcity pricing might facilitate the exercise of market power in spot market	Scheme could have material administration costs Possible increased costs from over-building, sub-optimal plant mix or reduced efficiency Possible exercise of market power in contracts market because customers are forced to hedge
172N 2(g) Electricity sector contributes to achieving the Government's climate change objectives	Unlikely to materially alter outcomes (e.g. hydro spill), as compared to status quo (other than in short term as system adjusts to new settings)	Unlikely to materially alter outcomes (e.g. hydro spill), as compared to status quo (other than in short term as system adjusts to new settings)
Ease of implementation	There area number of issues, but measures are broadly compatible with current arrangements and can be phased in. International experience can be drawn on from a variety of markets (e.g. Australia, Texas, Scandinavia)	Challenging design and implementation issues. Significant implementation costs and risks Limited international experience of energy-adequacy schemes (Colombia began scheme in 2008)
Transition issues	Relatively straightforward to implement in its own right. Transition would need to dovetail with measures to facilitate competition and market monitoring etc. Participants may require advance notice to allow them to adjust their portfolios (depending on specific option)	Significant lead-time required to establish arrangements Existing contracts may need to be revised, unless significant transition allowed

	Scarcity/compensation	Compulsory contracting scheme
Key risks	Potential for increased exercise of market power in spot market/undue price volatility	Likely bias toward over-building and reduced downward pressure on costs

Q3	What is your assessment of pros and cons of scarcity pricing approaches versus compulsory contracting?

Q4	What other broad options should be considered to improve security performance?

5.1.7 In summary, the chief advantage of the compulsory contracting approach would be the higher level of assurance it provides around security. However, it would be complex to implement and administer, take a considerable time to put in place and impose significant costs. For these reasons, the Commission does not see merit in proceeding with a compulsory contracting regime at this time. Instead, the Commission believes this option should be retained as a fallback.

5.1.8 As regards the scarcity pricing/compensation approach, the key issue is the trade-off between the security benefits versus its potential impact on the exercise of market power/undue price volatility.

5.1.9 Based on experience in other markets and the factors discussed elsewhere in this paper, the concerns around the exercise of market power/price volatility should be able to be addressed. Furthermore, scarcity pricing would not create a 'new' cost in a shortage event – this cost already exists in the form of unserved demand. The key change would be to make the cost of any shortage transparent to wholesale market participants – so they have incentives to minimise it, for example by procuring earlier voluntary demand reductions.

5.1.10 For these reasons, the Commission sees merit in exploring the scarcity pricing/compensation approach in sufficient detail to develop a 'working model' of the proposal. This would then be assessed against the status quo to weigh its relative benefits and costs.

5.2 Possible pathways for adopting scarcity pricing

5.2.1 If scarcity pricing were to apply, there are two broad pathways by which it could occur:

(a) **Option A - Pure scarcity pricing** – apply VOLL pricing for actual shortage situations, but not adopt any scarcity pricing arrangements for pre-shortage events;

(b) **Option B - Modified scarcity pricing** – undertake a phased implementation, with the initial step being the introduction of administered price floors for pre-shortage situations (e.g. public conservation campaigns). VOLL pricing for actual shortage situations could be introduced subsequently if required.

5.2.2 Option A has the advantage that it would involve the least amount of intervention in market arrangements, and therefore preserve the greatest scope for market based innovation. The core change would be to ensure that a scarcity value[22] for lost load is reflected into spot prices at any node affected by forced demand curtailment.

5.2.3 There would be no requirement to define formal arrangements for pre-shortage events. Instead, spot prices would be set by market forces in these situations and be expected to reflect the increased likelihood of power cuts being required subsequently. Provided the overall approach is viewed as sustainable and credible by market participants, it should have the desired beneficial effect on incentives.

5.2.4 The main concern with Option A is the potential for the exercise of market power/associated price volatility. This concern is greater for *actual shortages* than for *pre-shortage* events (e.g. public conservation campaigns) because the associated scarcity values are much higher in the former situation[23]. For this reason, a phased approach might be attractive, based on the application of minimum default spot prices during pre-shortage events, but with other existing spot price arrangements being unchanged. Scarcity pricing for actual shortage could be introduced subsequently, if experience indicated that it was required.

5.2.5 Option B would be more complex to implement than Option A in some respects because of its broader scope. For example, a price floor and trigger condition would need to be defined and applied for major pre-shortage events such as public conservation campaigns[24]. However, some other implementation issues may be eased under Option B's phased approach. In particular, the need for measures to address risks associated with the exercise of market power would also be phased, with less intrusive measures being required at the outset for Option B as compared to Option A.

5.2.6 Another consideration is the relative impact on incentives to undertake investment/demand response under the two approaches. This issue is explored in Appendix 5, which seeks to disaggregate the value of scarcity pricing between pre-shortage and shortage situations. As expected, this analysis indicates that the incentive benefits of Option B are likely to be lower than Option A. Nonetheless, a material improvement could be expected under Option B. This arises because pre-shortage events occur more frequently than actual shortages. As a result, they can generate significant expected revenue for providers of new

---

[22] The precise mechanism has not been defined, but it could be via a surrogate demand-side bid at VOLL, or some adjustment to ex-post prices.

[23] Ensuring that spot prices reflect VOLL during actual shortage situations (such as rolling cuts) should improve incentives. However, retailers with customers on variable volume fixed price tariffs may still not have sufficient incentive to invest in adequate reserves unless they are required to compensate customers (e.g. through a default buyback arrangement).

[24] It would be desirable to do this in a way that does not disturb efficient dispatch, and this appears feasible.

supply/demand response, even though the associated scarcity values are much lower than for actual shortage events.

5.2.7 Another factor to consider is the perceived policy sustainability/resilience of the two options. This is important because attaining the desired objective relies on market participants altering their investment plans and behaviour.

5.2.8 Option A has the virtue of having fewer points for debate and policy interpretation. However, it ultimately relies on the threat of very high spot prices being applied in any actual shortage. Given the expected infrequency of such events and the potentially severe financial consequences that would be imposed, market participants might doubt whether this will occur in practice. By contrast, the more graduated approach in Option B may be more credible. It may also carry a lower perceived risk of unexpected interventions during a security crisis. This is because government (through the regulatory body) has a more active role to play before any forced power curtailment takes place.

Q5	What approach to scarcity pricing should be preferred?

6. Next steps

6.1.1 Figure 4 summarises the broad options considered in this paper to improve security (noting that changes to the Reserve Energy scheme are being considered in a different context). In particular, the diagram highlights the key differences between scarcity pricing and compulsory contracting approaches in terms of:

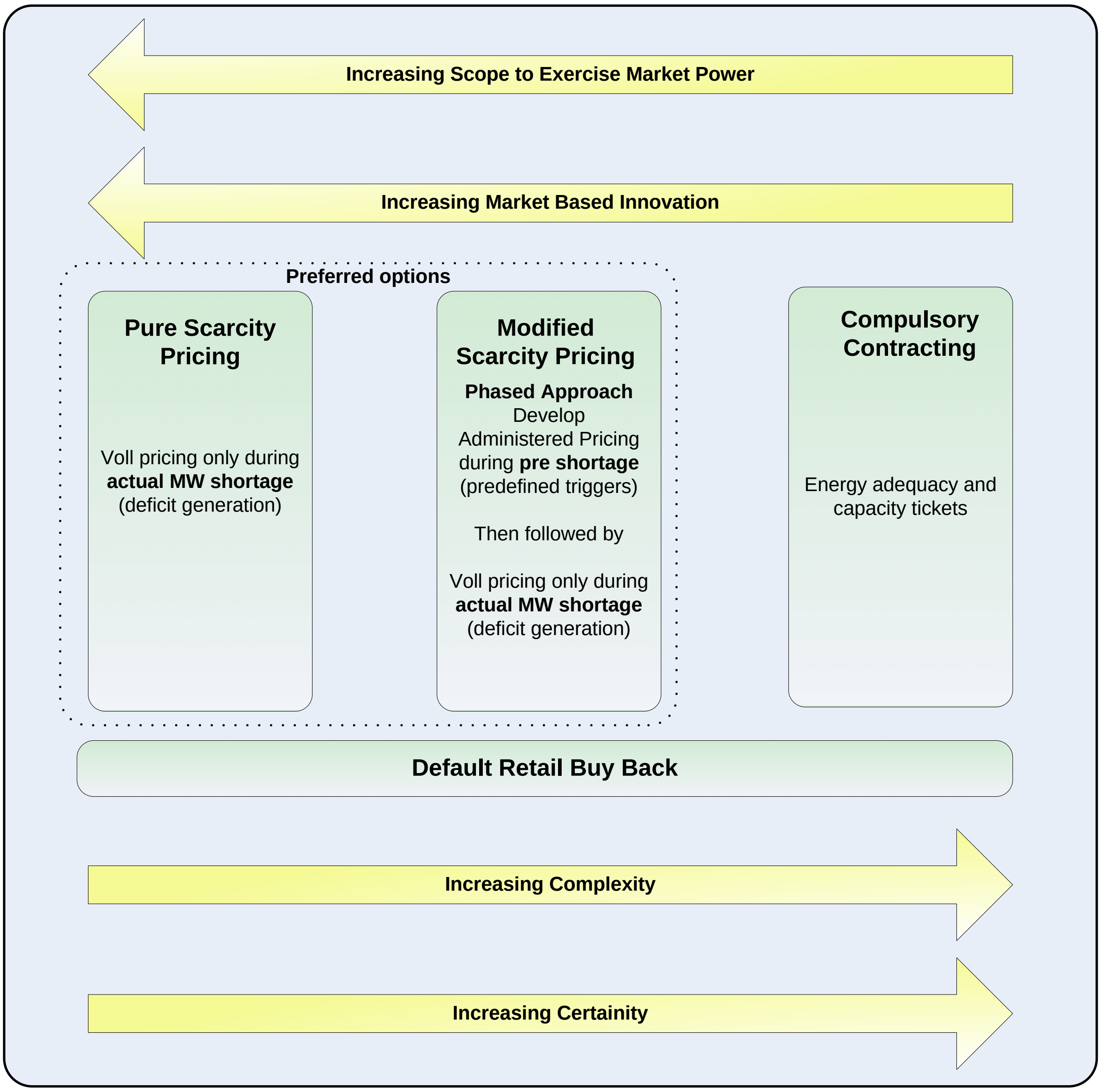
(a) scope for ongoing market-based innovation;

(b) the extent to which they might increase the scope for the exercise of market power;

(c) the degree of implementation and ongoing complexity; and

(d) the degree of certainty of achieving the desired security objectives

Figure 4 – Summary of alternative approaches



6.1.2 Having weighed these different factors, the Commission intends to proceed on the following basis:

(a) compulsory contracting should not be pursued further at this time, but should be retained as a fallback option if scarcity pricing/compensation mechanisms prove to be unattractive;

(b) a detailed proposal for a scarcity pricing regime should be developed – based on the Pure Scarcity Pricing approach (Option A) or the Modified Scarcity Pricing approach (Option B);

(c) a detailed proposal for a default buyback arrangement (compensation) should be developed, which would apply to mass market retail customers during any official demand conservation campaign; and

(d) to accompany these measures, work should be progressed on a range of supporting initiatives. This would include work on:

(i) Pro-competitive measures;

(ii) Enhanced market monitoring;

(iii) Review of prudential and related arrangements

(e) the approach reflected in (b) – (d) would be developed to a point where it enables a robust assessment of costs and benefits to be made, relative to the status quo.

6.1.3 The Commission welcomes the views of submitters on these proposed next steps. The Commission will take these views into account as it makes decisions on how to move forward.

Q6	Do you agree with the outlined approach whereby the Commission will progress with a detailed proposal for a scarcity pricing regime and for a default buy-back arrangement? If not, what would be the best approach for moving forward?

7. Summary of questions

Q1 What concerns do you have with regard to security of supply under existing arrangements?

Q2 What, if any, other underlying issues lead to the potential for cost shifting among market participants?

Q3 What is your assessment of pros and cons of scarcity pricing approaches versus compulsory contracting?

Q4 What other options should be considered to improve security performance?

Q5 What approach to scarcity pricing should be preferred?

Q6 Do you agree with the outlined approach whereby the Commission will progress with a detailed proposal for a scarcity pricing regime and for a default buy-back arrangement? If not, what would be the best approach for moving forward?

Appendices

Appendix 1 Format for submissions 39

Appendix 2 Scarcity Pricing Mechanisms.. 41

Appendix 3 Default buyback mechanism 53

Appendix 4 Compulsory contracting arrangements.. 56

Appendix 5 Scarcity pricing and investment incentives..................................... 63

Appendix 1 Format for submissions

The Commission's preference is to receive submissions in electronic format. If possible, submissions should be provided in the following format.

Where you are responding yes or no to a question, please provide general comments in support of your response

Question No.	Question	Response	General comments in support of response

Appendix 2 Scarcity Pricing Mechanisms

(a) This appendix describes the some of the key features of scarcity pricing mechanisms, and the issues that would need to be addressed if they were to be implemented in New Zealand.

(b) Most of the appendix focuses on situations of actual shortage – i.e. when demand is forcibly curtailed. There is also a brief discussion of scarcity pricing during an IR shortfall..

2.2 Possible triggers to apply scarcity pricing

(a) Scarcity in this context refers to a situation where consumers experience reduced security or actual curtailment as a result of an *administered* action.

(b) In New Zealand, security problems could arise due to energy shortages (generally in dry years) or capacity shortfalls (ability to meet peak demand). For this reason, there are four main administrative actions that could be used to trigger scarcity prices. These are summarised in Table 3.

Table 3 – Possible situations where scarcity prices might be applied

	Pre-shortage	**Actual shortage**
Dry-year energy adequacy	Public conservation campaign	Rolling power cuts
Real time capacity adequacy	Reducing instantaneous reserves cover below normal level	Enforced power cuts following a Demand Allocation Notice issued by System Operator

(c) The adoption of scarcity pricing is not an all or nothing choice. Indeed, the issues and implications of scarcity pricing are different for each quadrant, and there might be merit in applying it on a selective basis.

2.3 Setting the value for scarcity prices

(a) In principle, scarcity prices should reflect the specific circumstances of a demand curtailment event. Most importantly, scarcity values should distinguish between pre-curtailment events (reserves shortfall or public conservation campaign) with lower costs, and actual curtailments where costs to users will be much higher. In the case of actual curtailments, costs will be different depending on:

(b) the types of customers affected – residential, commercial and industrial consumers may have different values of lost load;

(c) duration – the length of an outage can affect the size of a loss;

(d) time of day/season – an outage in a winter weeknight evening might be more inconvenient than one in a summer weekend morning;

(e) advance warning – notice of possible outage will be likely to reduce costs of any actual outage. For example, a production plant may be able to reschedule operations to reduce the effect of an outage if given sufficient warning.

(f) On the other hand, there are strong arguments for providing market participants with certainty about the price level, and for this reason a set of 'standard values' might be adopted.

(g) This is the approach commonly taken internationally. For example, the Australian National Electricity Market (NEM), the Irish Single Electricity Market (SEM) and the Nord Pool Elspot all apply single values for scarcity prices. New Zealand also currently uses a single figure for evaluating transmission investment proposals.

(h) However, there is one feature of the New Zealand market which suggests that at least two values for shortage might be appropriate. With dry year risk, there is a greater likelihood that some forms of demand interruption can be anticipated hours or even days in advance.

(i) This factor suggests that two scarcity price figures for actual curtailment might be appropriate:

(j) Pre-notified curtailment: this figure should represent the cost to users of lost load when some minimum notice of impending curtailment is provided, e.g. rolling cuts during a hydro shortage;

(k) Curtailment without notice: this figure would represent the cost to users of lost load without prior notice to users, e.g. demand allocation notices issued for real time security.

2.4 Basis for determining scarcity values

(a) Two broad methods of determining a value for lost load (VoLL) have been used in other markets – consumer surveys and the marginal cost of supply, as detailed below:

Method	Positives	Negatives
Consumer surveys – surveys are undertaken to ascertain the value that a consumer would willingly pay to avoid having their electricity supply interrupted (willingness to pay – WTP) or alternatively the minimum amount they would require to accept an interruption (willingness to accept – WTA).	Adopting a VoLL value on this basis ensures that demand-side response mechanisms are maintained.	Interviews can be problematic, because people have to answer questions about trade-offs they rarely make. Consumers' answers may be influenced by the way in which interview questions are framed, status quo bias in that consumers are prejudiced towards no more and no less interruptions than they currently experience, and consumer scepticism that electricity prices really will drop if reliability is decreased.[25] The paper prepared by Concept Economics at http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/pdfsgeneral/Value-of-use-final-report.pdf provides an explanation of how to deal with these concerns.
Marginal cost of supply – VoLL can be derived from the fixed and variable costs of a best new entrant peaking plant.	Adopting a VoLL value on this basis ensures that supply-side investment signals are maintained for electricity producers.	However, given the potential variability in such costs, there is a trade-off between stability of VoLL value for market participants and accurately reflecting the marginal supply cost. It is likely that a cost-based approach to determining a dry-year VoLL figure would be more difficult than determining a peak VoLL as, fundamentally, it is more challenging to value energy than capacity.

(b) In both the Australian NEM and the Irish SEM, VoLL is calculated using the marginal cost of supply basis. Specifically, Australia's NEM uses the cost of a new open cycle gas turbine as the basis for meeting the system reliability standard (not more than 0.002% unserved energy), while Ireland's SEM uses a value for VOLL derived from the fixed and variable costs of a peaking plant and the generation security standard (an estimate of the cost required to reduce load shedding to eight hours a year).

[25] De Nooij, Koopmans and Bijvoet (2007) De Nooij, M., C. Koopmans, and C. Bijvoet. *The value of supply security – The costs of power interruptions: Economic input for damage reduction and investment in networks*, Energy Economics Journal, 29 (2007) 277-295.

2.5 Default price level or price floor

(a) Some markets treat the administered scarcity price as a fixed level, such as Australia's NEM. This level also acts as a cap in that market.

(b) Ireland's SEM also has a price cap but it is set at a value significantly lower than the default level of VoLL. In Nord Pool's Elspot, there is no cap on the wholesale market.

(c) In contrast, the Swedish balancing market treats the administered default price as a market floor during any scarcity event.

(d) The principal advantage for adopting a price cap is that it provides certainty to market participants as to the maximum level for market prices, and hence their exposure to financial risk.

(e) If the default price is to be used as a market cap, setting it at an appropriate level is critical. A cap that is too low could:

  (i) alter the portfolio of plant on the system away from the efficient mix. For example, it may inhibit the development and use of options with high variable costs and low fixed costs;

  (ii) reduce the incentive on users to enter sufficient fixed-price forward contracts with generation unit owners, and therefore increase risks around security of supply; and

  (iii) reduce the opportunities for demand-response.

(f) These issues do not arise if the default price is treated as a floor rather than a default level/cap, although it is obviously also important to ensure that it is not set at an overly high level.

(g) Importantly, if administered scarcity prices were to be applied in pre-shortage situations, they should be applied as a floor, since there is a significant risk of the triggering perverse outcomes if they were to operate as a cap.

(h) It is also important that the administered pricing mechanism does not significantly distort short run dispatch of the system within the day and across the transmission grid[26].

2.6 Nodal prices, locational hedges and scarcity pricing

(a) Electricity prices in the New Zealand spot market are 'discovered' simultaneously at over 240 nodes, with differences between nodes reflecting estimated marginal losses, or relative local supply/demand balances if transmission flows between two locations have reached the technical limit.

---

[26] The details of how this could be achieved will need to be considered at a later stage, but one possible way to minimise the impact might be to continue the current dispatch and pricing mechanisms, but then apply a daily surcharge to final spot prices as required to prevent the rolling average weekly spot price falling below the floor.

(b) In principle, scarcity could arise at a single node due to a localised generation or transmission constraints. In that situation, if scarcity pricing were applied, the local price would reach very high levels. In practice, localised issues are almost always associated with a transmission outage of some kind.

(c) This raises the question as to whether scarcity pricing should apply when demand curtailment is caused by transmission outages. Relevant factors include:

    (i) if curtailment is caused by transmission outages and the transmission provider is not liable for 'non-performance', scarcity pricing may not improve overall incentives;

    (ii) conversely, if transmission capacity is limited or unreliable, this could arguably be offset by 'local' generation, and scarcity pricing could provide a useful incentive.

(d) While it may in theory be possible to exclude transmission related shortfalls, it would appear problematic in practice. For example, if South Island power cuts had been required during the winter of 2008, would they have been 'due' to generation shortage, or the withdrawal of Pole 1 of the HVDC (which was announced six months earlier)?

(e) This suggests that it would be more practical to treat all outages on a similar basis, which is the approach adopted in some other markets such as the Australian NEM. For major nodes on the 'back bone' of the grid within each island this may be acceptable, as there is sufficient diversity of supply (including via transmission) to enable reasonable competition. However, wholesale purchasers on the fringes of the grid would be subject to considerable price risk.

(f) Under current arrangements, this degree of risk would be very difficult for wholesale purchasers to manage. However, this would improve if the current locational hedging proposal were to be implemented. Under that proposal, wholesale purchasers in each island (or major sub-region of an island) would pay the generation weighted price for their electricity, provided their usage matched their locational hedge entitlement. To the extent their usage was above or below their entitlement, they would be exposed to the local spot price (in this case a scarcity value).

(g) This arrangement, if implemented, should significantly reduce the price risk for wholesale purchasers arising from localised transmission constraints.

(h) As regards other features of the locational hedge proposal, it appears to be compatible with scarcity pricing. In particular:

    (i) wholesale purchasers would face the marginal *locational* price signal to the extent that were operating away from their locational hedge entitlement level – this would preserve incentives for short-term demand response, while significantly reducing the absolute level of risk they face (relative to current arrangements);

(ii) locational hedge products should increase the depth of the energy hedge market, making it easier for parties to manage energy spot price volatility;

(iii) scarcity pricing could be applied in a manner that would not affect rentals (other than where scarcity is localised, in which case it would be desirable).

2.7 Effect on wholesale market risk and competition

(a) While scarcity pricing should ensure that spot prices more accurately reflect the value of electricity (i.e. lost load) in a situation of market distress, participants are likely to be concerned about increased price volatility. To a degree, this concern is inevitable, as the prospect of high spot prices provides the driver for increased hedging, and the revenue base to support peaking/reserve generation plant and voluntary demand response.

(b) However, it is important to ensure that risks are not unmanageable (or perceived as such). It this context, legitimate concern is likely to focus on three issues:

(i) Exercise of market power, leading to contrived rather than genuine scarcity;

(ii) Unintended outcomes, for example through mis-specification of the pricing model; and

(iii) Extreme events, for example a major earthquake on the alpine fault which knocked out much of New Zealand’s generation capacity.

(c) These concerns are likely to be most acute in respect of default prices for actual outages, as compared to pre-outage events, because of the marked difference in price levels.

(d) These issues have arisen in other markets and have been dealt with in a number of ways.

(e) The issue of market power arises under current arrangements, and it not clear that default pricing would fundamentally alter the dynamics in the New Zealand market, especially as there is currently no cap on spot prices. Concerns about market power are best dealt with in their own right, and that is the approach being taken by the Electricity Commission. For example, it sees the proposed introduction of locational hedge products as an important tool to facilitate competition in the hedge and retail markets. The possible introduction of scarcity pricing would reinforce this objective.

(f) A second approach is increased market monitoring to detect and deter any undue exercise of market power. This forms a key part of the approach in the Australian NEM. For example, an event report is prepared by regulatory authorities whenever spot prices exceed $5,000/MWh. Among other things, these reports look at market behaviour in the period leading up to high prices, and the actions of parties during those periods.

(g) In respect of unintended high prices, the main risk is mis-specification of inputs to the pricing model. While there is already a documented process for running these models, it may be useful to review arrangements to ensure they are sufficiently robust. Event reports would also provide an important safeguard[27].

(h) 'Extreme event risk' could be handled in a number of ways. One approach is to leave it to private parties to address in their bilateral hedge contracts. For example, contracts could contain force majeure clauses that limit the contractual obligations in extreme situations, which could be defined on a physical basis or by reference to some (extended) period of high spot prices. Generally speaking these arrangements will be tailored to the specific circumstances of the two counterparties, i.e. the supplier's obligation to provide price insurance might be suspended if its *own plant* was seriously impaired by an extreme event.

(i) Another approach is to address the issue through general market suspension provisions to be triggered by the market operator or regulator if 'disorderly' conditions emerge. The broad equivalent in current arrangements is the provision related to Undesirable Trading Situations under Part 3 of the Electricity Governance Rules. These might need to be clarified or extended if scarcity pricing were to be introduced.

(j) A related issue is whether any limit should be applied to the duration of scarcity pricing. Any such limit would help to mitigate the risks noted above. This is the approach taken in the Australian NEM where a cumulative price threshold operates, and is triggered if cumulative prices reach A$150,000/MWh over the previous week (equivalent to an average of A$446/MWh).

(k) If that occurs, an administrative price cap of $300/MWh applies, although parties are able to seek compensation if they can demonstrate that this price does not cover their costs.

(l) The main argument for such a threshold is that it provides more certainty to parties about what will happen in a prolonged and extreme event. In the NEM, such events are not expected due to the capacity constrained nature of that market. This is not true of New Zealand, because droughts can last for weeks or months. The risks of undermining incentives through a cumulative threshold are therefore greater in New Zealand than Australia. This suggests

---

27 A similar concern arises in relation to outages caused by automatic under frequency load shedding (AUFLS). If these are triggered, because of their 'block' nature, there is a potential for more load than strictly necessary to be shed, which by implication means that some generation will also be required to ramp down. The allocation of load and generation shedding to market participants would in a sense be 'uncontrolled', leading to unpredictable outcomes on individual market participants. For this reason, it is not currently proposed that load shedding caused by AUFLS would trigger any default scarcity pricing.

that a cumulative limit would need to be carefully designed to avoid unintended effects in New Zealand.

2.8 Quality of 'real time' information

(a) A key objective of scarcity pricing is to improve signals to allow market participants to take action ahead of time. Put another way, the benefit of scarcity pricing will be eroded if parties cannot alter their actions in the light of price signals.

(b) This raises a question of whether signalling mechanisms are likely to be sufficiently robust – especially for short term events (as opposed to dry year risk).

(c) There are two key aspects to this question:

    (i) Do forecast prices have sufficient 'integrity'? For example, are they based on data that is adequate in terms of expected demand, transmission flows etc?

    (ii) Are decision makers able to access the appropriate information? For example, can they assess the risk of very high prices?

(d) Work undertaken by the Commission has already identified a number of areas that can be improved and this is underway.

2.9 Transition issues

(a) The introduction of scarcity pricing and any subsequent changes to key parameters (e.g. default price levels) has the potential to cause wealth transfers among market participants. For example, it could alter the value of existing hedge contracts because of a perceived change in the risk of very high spot prices.

(b) However, it is important to place such changes in perspective. While scarcity pricing may alter the shape of spot prices, it should not materially alter average spot prices, as these will be influenced mainly by the cost of new supply.

(c) Nonetheless, if there is concern about the potential for transfers of value in relation to existing contracts, this concern could be mitigated by ensuring there is a reasonable lead time before changes take effect. This is the approach that has been applied in other jurisdictions.

(d) Ireland's SEM recently introduced scarcity pricing. The Regulatory Authorities determined that there should be no review of VoLL during the first year of operation. Furthermore, the value of VoLL is to be re-examined, and reset if necessary every five years, using the methodology set out by the Regulatory Authorities.

(e) The Australian NEM has had scarcity pricing for several years now. Recently the Australian Energy Market Commission (AEMC) Reliability Panel determined that a two-year review of VoLL was preferable to one-year review, with any changes to be given with a two-year notification period. This means that, at the very least, market participants would be given a two year notice of any change, and VoLL would not change more frequently than once every four years.

2.10 Scarcity pricing for instantaneous reserves shortfall

(a) The preceding discussion focussed on situations where demand is forcibly curtailed. Another form of scarcity is a shortfall in the instantaneous reserves market.

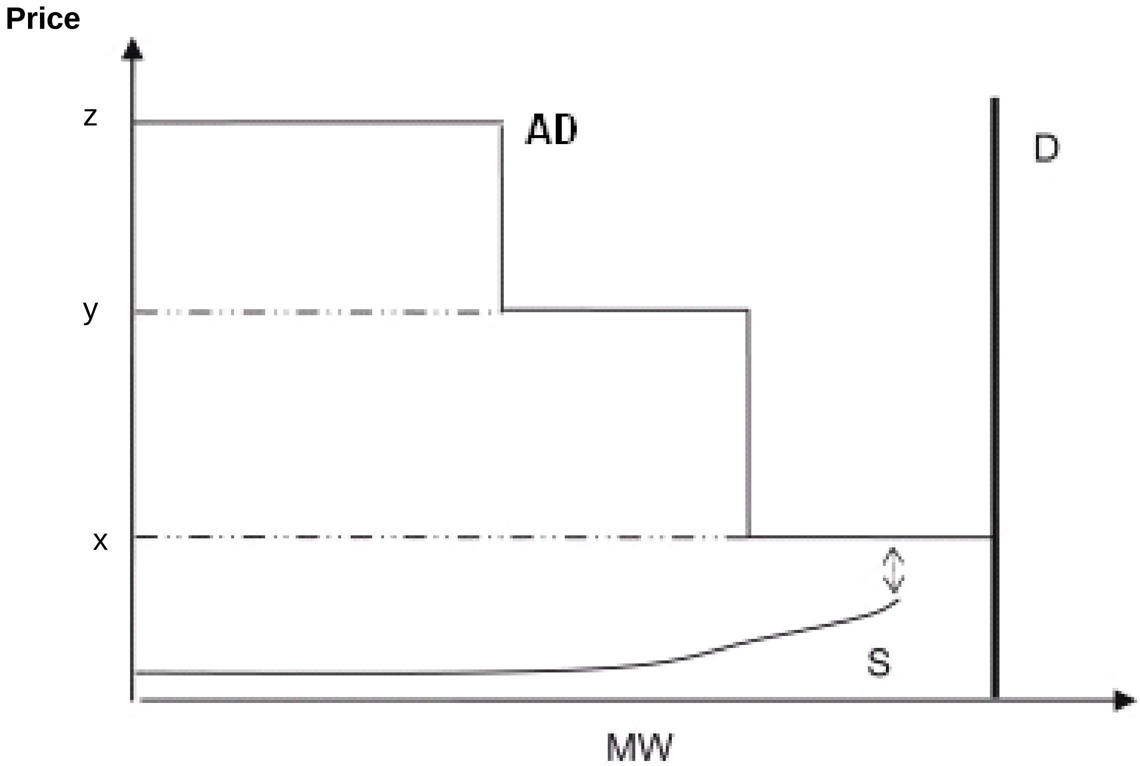
(b) In the US, four markets currently have a form of scarcity pricing for reserves: NYISO, ISO-NE, MISO and PJM. CAISO is also intending to implement scarcity pricing for reserves. The form of scarcity pricing varies, but a multi-step scarcity pricing mechanism applied on a locational basis is the design to which Regional Transmission Operators appear to be converging[28].

(c) This could be implemented in a number of different ways. One approach would be to apply 'scarcity values' to differing levels of shortfall. The key features of this approach are shown diagrammatically in Figure 5. The administrative demand (AD) curve is shown as a stepped function at three different prices. The 'curve' has steps because there is an increasing probability of demand curtailment being required as the level of reserves decreases[29]. For this reason, the expected value of reserves (i.e. value x probability of use) is higher when there is limited availability and vice versa.

[28] For example, see recent determination of the Federal Energy Regulatory Commission, Washington DC

[29] In reality, the function may have steps or smooth contours in different regions. It is drawn this way for ease of explanation.

Figure 5 – Scarcity pricing for reserves shortfall



(d) In this particular case the actual demand for reserves is shown by the demand curve (D), and there is no intersection point between supply and demand as there are simply insufficient reserves. Consequently, in this example, the price would be set at x. Had the reserve shortage been more significant, it may have been set at y or z (which could be several thousand dollars per MWh).

(e) The trigger for a shortfall in instantaneous reserves is relatively clear-cut, given the requirement to maintain sufficient operating reserves in each island to offset the largest single contingent risk in that island.

(f) The value to apply during an IR shortfall would be lower than for actual demand curtailment. In principle, the value should be based on the value of actual demand curtailment, x the probability of it occurring. As noted above, this could be in the form of a smooth or stepped curve reflecting the rising probability of AUFLS being triggered as the level of available IR declines.

2.11 Application of scarcity pricing in other markets

(a) Scarcity price mechanisms have been implemented in a number of energy markets. These include:

(i) the Australian National Electricity Market (NEM) applies a scarcity price during forced demand curtailment of A$10,000/MWh (increasing to $12,500/MWh)[30];

(ii) Nord Pool (covering Norway, Sweden, Finland, Denmark and North Eastern Germany) applies a scarcity price of €2,000/MWh in the Elspot day ahead market if demand exceeds supply;

(iii) the real time balancing market in Sweden applies a default floor price of 20,000 SEK/MWh during forced demand curtailment;

(iv) the Single Electricity Market (SEM) in Ireland applies a scarcity price during any forced demand curtailment;

(v) four regional wholesale electricity markets in the United States (NYISO, ISO-NE, MISO and PJM) currently apply a form of scarcity pricing to instantaneous reserves shortfalls, and CAISO also intends to adopt this approach; and

(vi) the gas market in Victoria applies a scarcity price during a forced demand curtailment.

---

30 Although the financial consequences of this are mitigated by a Cumulative Price Cap.

Appendix 3 Default buyback mechanism

3.1 Objectives

(a) The mechanism is designed to address the following objectives:

   (i) Policy sustainability – address concern that retailers ‘profit’ from conservation campaigns at present (because their spot market purchase costs are reduced by lower prices and lower volumes);

   (ii) Efficiency – address undue reliance on mass-market conservation campaigns as tool to manage dry year risk; and

   (iii) Demand-side response – encourage development of market-based demand side response.

3.2 Key elements

(a) Retailers would be required to pay customers a compensation sum during any ‘official’ conservation campaign – the amount would set at a level to reflect retailers’ savings from reduced wholesale purchase costs.

(b) Retailers would not be required to pay compensation to customers on contracts with in-built demand response rewards (to encourage development of market-based contracts rather than reliance on default mechanism).

3.3 Coverage

(a) The mechanism would cover all residential users as a minimum (to address objective a). Coverage might also include small to medium sized enterprises that had fixed price, variable volume contracts. Business customers on fixed volume contracts would not be covered – as they have an incentive to reduce demand when spot prices are high.

3.4 Trigger

(a) The mechanism would be triggered by a declaration by the Electricity Commission – operating to guidelines that it had previously established and published[31].

(b) In broad terms, it is expected that mechanism would not be triggered unless and until:

   (i) All available non-hydro plant was running to full capacity

---

[31] Such as the “emergency zone” currently published by the Electricity Commission.

(ii) Any reserve energy sources with a cost of less than $500/MWh was operating

(iii) There was a material likelihood that shortages would occur in the absence of a national campaign

(c) Likewise, the Electricity Commission would determine criteria for declaring when a campaign would cease, and be responsible for making the declaration.

(d) It is possible that retailers may seek to run their own public conservation campaigns before an official campaign is triggered. This might be perceived as undesirable because retailers could seek savings without incurring buyback costs. In theory, this could be addressed by restricting retailers' ability to undertake such activity, or by instituting buyback rules from the outset of any such retailer-run campaign.

(e) However, each of these approaches has drawbacks, and it appears preferable to rely on customers making informed judgements. For example, if one retailer breaks rank, but the Electricity Commission and other suppliers maintain a different stance regarding the need for widespread conservation, customers will presumably make their own decisions about whether to respond to calls of the single retailer.

3.5 Level of compensation

(a) Compensation would be set at a level to reflect the value of demand savings to retailers. Preliminary analysis suggests a level of around $500-600/MWh, which equates to around $10/week or around $1/day for a residential customer using 800kWh/month and saving 10%.

(b) The simplest option would be to apply a flat $/day requirement across all target customers for the duration of any campaign.

(c) Arguably, this would tend to penalise retailers/favour customers in:

(i) areas where underlying electricity demand per household is lower due to higher penetration of gas;

(ii) warmer areas where heating demand is lower; and

(iii) areas where customers are less "community minded".

(d) It would be possible to make the scheme more targeted (e.g. link payments to level of regional savings, but this would be more complicated and still be open to debate). There would be a trade-off between simplicity and accuracy.

(e) If commercial customers were included, this would make the compensation calculation more complex, as their consumption levels differ markedly.

3.6 National versus regional issues

(a) It is possible that conservation efforts will only be useful at a regional level (e.g. lower North Island plus the South Island) due to the presence of transmission constraints. The arrangement should allow for regional campaigns to apply, again with only customers in affected areas receiving compensation.

3.7 Opt-out arrangement

(a) The arrangement is intended to provide a ‘default’ demand response term in standard contracts. Ideally, customers and retailers should develop bespoke arrangements that supplant the need for any default term.

(b) This could be accommodated by exempting customer contracts that had a alternative mechanism that provided an incentive for demand response in periods of sustained high spot prices.

(c) The mechanism by which this opting out could occur would need to be carefully considered, as ‘penalty’ arrangements might be viewed as less acceptable than ‘reward’ arrangements, at least in the short term, even though they arguably achieve the same effect.

(d) One approach would be to provide a set of ‘template terms’ that retail contracts could contain. If the contract contained one of these options, it could be regarded as compliant with the requirement to encourage demand response.

(e) This is an issue that requires further consideration.

3.8 Exit terms

(a) It would be important to ensure that retailers could not circumvent the arrangement by terminating their supply arrangements with customers. In principle, this should be covered under the standard notice period in contracts, but this should be confirmed. Regulation may be required to address this issue.

3.9 Verification issues

(a) Enforcement could be largely based on a penalty regime applied to any cases of non-compliance. To keep the mechanism simple, this could rely on customer complaints as the trigger for any investigation – rather than an explicit audit mechanism.

(b) Compliance as regards ‘qualifying opt-out tariffs’ is probably the main challenge. To keep this simple, it could be based on a model contract term, as noted above.

Appendix 4 Compulsory contracting arrangements

This appendix describes the some of the key features of compulsory contracting arrangements, and the issues that would need to be addressed if they were to be implemented in New Zealand.

4.1 Objective

(a) The objective of compulsory contracting arrangements is to ensure that there is sufficient physical supply capacity and energy capability to meet demand in adverse conditions (e.g. peak demand with plant outages, or energy demand during a dry year). A secondary objective in some jurisdictions is to ensure that unresponsive customers are protected from very high *spot* prices (noting that this must be paid for via higher *contract* charges).

(b) There are many capacity or energy schemes possible but they all involve the following key elements to some degree.

4.2 A security administrator

(a) All of these schemes require some central body to set, monitor and enforce the obligations and to run tenders if required. For this discussion it is assumed the Commission has this role, but it could be the System Operator or some other specially constituted body.

4.3 Adequacy tickets

(a) Adequacy can be measured in physical terms (an absolute requirement to hold entitlements to MW or MWh) or financial terms (a requirement to have insurance against spot prices rising above a pre-defined level such as the variable cost of a diesel-fired generator). Both mechanisms can achieve the same required security objective, but the latter approach is more flexible and easier to implement.

(b) In situations with competitive retail markets, the obligation is often expressed in terms of standardised capacity or energy ‘tickets’. For example, it could be in the form of:

   (i) a financial call option with a strike price less than the variable cost of oil-fired back-up generation (say $300/MWh), or

   (ii) a firm forward financial contract, or

   (iii) actual or contracted ownership of physical plant and fuel (or stored water) capable of providing the capacity and energy capability in adverse conditions when spot prices exceed $300/MWh, or

(iv) voluntary demand response from contracted end-use customers during adverse conditions.

4.4 Retailer obligations

(a) Retailers would be required to have capacity or dry-year energy ‘tickets’ to cover a specified fraction of their forecast end-use customers’ load.

(b) The fraction would reflect the prevailing capacity or energy standards. This could be (say) 117% of peak load for capacity adequacy, or (say) 98% of energy consumption in a dry winter period for energy adequacy.

(c) The obligation could be based on the projected level of load in the coming year, or some years ahead.

(d) Individual retailers could be responsible for their own forecasts, or forecasts for each customer/tariff category could be determined centrally with each retailer responsible for its current market share.

(e) A vertically integrated retailer could have tickets issued from its generation arm or from other generators. Where there are transmission constraints regional obligations may be needed.

4.5 Generator obligations

(a) To provide confidence that the security standard is being met, generators would need to be restricted from issuing more ‘tickets’ than they have ‘firm’ capacity or energy capability to back up in a dry-year.

(b) It is relatively easy to assess generation MW capability for unconstrained thermal, geothermal and hydro plant. However, it is much more difficult to assess the MW and MWh capability of wind, run-of-river and constrained hydro. In principle, diversity between fuels, wind and hydro schemes should be allowed for, and this further adds to the complexity.

(c) In general, generators will be in a much better position to assess the capability of their assets and so the simplest approach would be for the Commission to provide some guidelines and to set some broad limits, but otherwise allow generators to self declare their capacity and dry-year energy capability. There would need to be stiff penalties in place to deter over-estimation of ‘firm’ capability.

(d) Alternatively the capability could be assessed centrally on the basis of information (e.g. historical data, conversion efficiency, resource consent limits etc) provided by generators. Generators may need some appeal rights in this case.

4.6 Monitoring and enforcement

(a) Some form of central registry recording the number of tickets issued by each generator and held by each retailer would be required to assess compliance. This would need to handle transfers between parties to deal with changing market shares and new conditions.

(b) Enforcement could be carried out ex-ante (i.e. parties are assessed on forecast load and future tickets) and/or ex-post (i.e. parties are assessed after the event). The most light-handed approach would be to allow generators and retailers to self declare their load and firm generation, and to rely on spot prices to provide the incentive to perform. However, this is arguably very little different to the current situation, so a more formal monitoring and enforcement arrangement is likely to be required.

(c) Note that if all retailers have contracts to cover their forecast load then they will not be exposed to spot prices above $300/MWh.

(d) Ex-ante monitoring and enforcement is likely to be required to ensure that retailers, industrial users and generators can meet their commitments in adverse situations, so they cannot pass the cost of any financial failure onto other parties. This would involve prudential requirements (margin calls and bonds etc), and/or monitoring of plant availability, hydro storage, fuel stocks, demands etc.

4.7 Pricing and cost recovery

(a) The cost to retailers of meeting the obligation to purchase tickets to cover their load is a cost of doing business, and thus would be passed on to customers.

(b) Some trading of tickets to allow for customer switching and changes to forecasts would be required. This could be organised through a central auction, or via bilateral trading. In either case prices should observable. Prices should be the expected value of spot prices exceeding the strike price ($300/MWh), and may be considerably higher depending on the penalty charges imposed on non-compliance. Long run ticket prices should not exceed the cost of building new reserve capacity (approximately $15-20/MWh). Revenue from the sale of tickets would be available to reliable baseload plant as well as new reserve capacity, and so there is no reason to believe that the total cost of supply would change materially (other than to recover the administration costs of the scheme). However, there is likely to be an inherent bias towards conservatism in forecasting load etc, which means that there will be some risk of over-build, with an associated cost.

4.8 Demand-side participation

(a) These schemes can allow for demand side participation as a form of reserve energy. However, such arrangements are difficult to design in a way that suits the different needs of individual customers. They can also be hard to monitor and enforce.

(b) It would seem reasonable that retailers would not be required to have ‘tickets’ for the proportion of end-use customer demand that has voluntarily chosen to be fully exposed to spot prices. This would allow larger customers to choose their own level of insurance consistent with their ability to respond voluntarily during periods of high prices.

(c) Demand response from mass market customers provides a relatively low cost form of reserve in a hydro dominated system such as New Zealand. It is important that any energy adequacy scheme allows this to continue. However, this needs to be achieved without over-frequent use of public conservation campaigns. Ideally retailers should be encouraged to develop commercial tariffs options which reward mass market customers for savings in dry-years. This could be achieved by reducing the obligation for retailers to hold tickets for loads on these tariffs.

(d) Allowing for demand response is likely to add some administrative complexity and costs, as it would require separate monitoring of static and responsive load, rather than just total reconciled load by retailer. There may be gaming issues if loads opt out when security risks are low and then opt back in when they are high.

4.9 Transitional issues

(a) Generators may already have issued hedges and retailers and large users may have already made their own arrangements for insurance. It is important that these prior commitments can be accommodated, at least during a transitional period while they phase out.

4.10 New Zealand specific issues

(a) Current New Zealand capacity and energy adequacy standards are specified differently to account for the HVDC constraints. This is likely to remain a significant issue until at least 2013, and possibly beyond.

(b) This would require separate energy adequacy obligations to be imposed in each island and an allocation of the inter-island capacity (from North to South) via transmission rights or some other mechanism. This could be used to limit the quantity of North Island dry–year capacity available to meet South Island load to be no greater than the inter island transfer limit.

(c) In addition New Zealand has regional transmission constraints which can cause significant nodal price variations within each island. This has consequences for the form of the ‘ticket’ (in that a reference node in each region may need to be specified) and may cause problems for generators that have issued tickets at other than their own node.

(d) Most schemes that have been proposed for New Zealand have focused on either the Energy Adequacy issue or the Capacity Adequacy issue. While the HVDC is constrained New Zealand faces joint energy and capacity constraints and these vary by island. Capacity adequacy is likely to become more of an issue in the medium term, particularly if substantially more wind generation is commissioned.

(e) It would be possible to introduce separate or combined energy and capacity obligations on retailers but this would increase administrative and compliance costs.

(f) Generators may be reluctant to enter a high level of firm financial contracts (i.e. 'tickets') given their complex and uncertain supply and their potential exposure to deficit penalties or high ex-post prices.

(g) Unless generators have a full balanced portfolio, or can enter into co-insurance schemes to share plant outage and other supply risks beyond their control, there is a risk that the number of tickets sold will be well below the 'after diversity' supply capability of the system. This is likely to be a more significant issue for small specialised generators or new entrant retailers. It would also lead to an over-estimate in the aggregate level of required generation.

(h) New Zealand is a small market and hence the additional administration costs can represent a significant cost to customers.

(i) The small size of the New Zealand market and the relatively small number of participants raises concerns about market power, and these are exacerbated when regional constraints are accounted for. Capacity/energy schemes can help address market power issues in the spot market by requiring or encouraging a very high level of contracting. However many of these concerns are simply shifted to the contracts or 'tickets' market. Incumbent generators may be able to profitably withhold capacity to increase the price of 'tickets'. It may be possible to impose a maximum 'ticket' price based on the full cost of new peaking capacity to deal with this. It would also be possible to ameliorate market power by allowing new entrants to compete, but this would require a contract term that is sufficiently long to build new plant (e.g. 2 years or more, assuming consents were already in place).

4.11 Possible options for New Zealand

(a) Several dry-year insurance schemes have been proposed for New Zealand in the past. These range from a fully decentralised scheme (WEMDG 1995) to a fully centralised scheme (M-Co 2003).

 (i) **Centralised**: The Commission identifies the aggregate need for dry year capability to provide the required energy adequacy standard, procures energy adequacy 'tickets' from generators on behalf of all customers through a tender. The Commission monitors and enforces obligations on generators with ex-post penalties if necessary. It allocates the costs and tickets back to retailers either at the end of the tender, or through a levy and difference payment rebate based on actual retailer loads.

(ii) **Centralised with opt-out**: This is the fully centralised scheme except that retailers who can demonstrate that they have contracts or dry year capability to meet their load can opt-out so the Commission only has to procure dry year capability for the residual load. This simplifies the transition from current arrangements and may significantly reduce (or even eliminate) the quantity centrally purchased by tender. It still enables the Commission to run a tender for longer term tickets if the market is not delivering sufficient new capacity to meet load growth and plant retirements over a 3-5 year horizon.

(iii) **Fully decentralised obligation**: the Commission sets the security of supply requirements, but leaves it to retailers to build or procure contracts as they see fit to meet those requirements. This is similar to the centralised model with 100% opt-out, so the Commission does not run a tender but relies on retailers to make their own internal or bilateral arrangements to meet their obligations.

(iv) **Prudential monitoring**: This is the fully decentralised model but with more light handed prudential monitoring. The Commission requires retailers and generators to self assess and report compliance and can require information (e.g. hydro and fuel stocks) to support these assessments. However, retailers and generators could choose the level they wish, subject to the requirement that they provide bonds, or some other financial guarantee, to cover their maximum financial exposure, taking into account registered energy ‘tickets’, to very high spot prices during a dry year contingency.

4.12 References

(a) There are a number of capacity schemes that have been operating in other markets for many years (PJM, New York, New England, Western Australia, etc), but only one scheme specifically addresses energy adequacy. This is the Firm Energy Market which was introduced in Columbia in 2007 and had its first firm energy auction in May 2008. This market is 77% hydro and is subject to significant hydro inflow variation like New Zealand. This is described in “Colombia Firm Energy Market”, Peter Cramton and Steven Stoft, December 2006

(b) There have been a number of variants of this type of energy adequacy scheme suggested for New Zealand in the past including:

(i) The scheme suggested by WEMDG in 1994, Appendix K of the WEMDG Draft Proposal March 1994.

(ii) This is further discussed in "Managing Dry Year Risk in a fully competitive Market: Issues and Options" and “Mandatory Security Hedges: Implementation Issues”, NZIER Report to OCEP, by John Culy, May 1995.

(iii) The scheme suggested in "Comparative Analysis of Reserve Capacity Options", M-co report dated 7 May 2003

(iv) The scheme suggested NERA as Option 2 in Contact's submission on the Proposed Generation Scheme, “Evaluation of Compulsory Dry-Year Generation Reserve Proposals for New Zealand”, NERA, June 2003.

(v) The scheme outlined on page 26 in "Comments on the NZ Reserve Generation Proposal", CRA report, 30 June 2003, as part of Meridian's submission.

(c) The following reports discuss issues and relative performance of these proposals.

(i) The alternative schemes are outlined and discussed in “Issues Concerning the Reserve Generation Proposal”, Morrison and Co Report to MED Jan 2004.

(ii) Potential integration of energy and regional capacity adequacy regime discussed in “Capacity Ticket Option Report” submitted to Contact CRA Jan 2005

(iii) A review of interventions for ensuring adequacy is given in “Electricity Security of Supply Policy Review”, Castalia, May 2007.

Appendix 5 Scarcity pricing and investment incentives

5.1 Objective

(a) This appendix explores the expected effect of adopting different forms of scarcity pricing on investment incentives.

(b) This issue has been examined by considering the possible impact on net spot revenues for an oil-fired peaker from different scarcity pricing options. The methodology and key assumptions for this analysis are drawn from the work carried out by the Commission to develop an energy adequacy standard[32].

(c) That standard was based on assumed costs of demand restraint as outlined below:

(i) 1-3% demand response from the market when spot prices reach $200-$500/MWh;

(ii) a 3% to 10% demand response from a range of public conservation measures at a cost of $500 to $2500/MWh; and

(iii) rolling outages as a last resort, with a cost between $5,000 and 20,000/MWh.

(d) The earlier work has been used to assess the expected frequency of these more extreme events, assuming the system is meeting the required energy adequacy standard. The results are summarised in Table 4.

Table 4 - Risks and Costs of Demand Restraint at Energy Standard

	Probability	Typical duration (weeks)	Return period (years)	Average cost of demand restraint ($/MWh)	Contribution to net value[33] ($/kW/yr)
'Normal Market' near miss ($200<x<$500/MWh)	4%	10-12	5-6	$300-$350	$40-$60
Public conservation (>$500/MWh)	0.4%	4-6	20-30	$700-$2,000	$20-$40
Rolling Cuts (>$2,500/MWh)	0.05%	2-4	80-100	$5,000 - $10,000	$20-$40
Total					$80-$140

[32] This work was carried out in 2007 in the development of the energy standard. It involved simulating the system over a range of historical inflows, plant outages and demand variations.

[33] This is the expected net spot market contribution to an oil fired reserve plant with a variable cost of $200/MWh.

(e) If the system is operating to the energy adequacy standard, rolling cuts might be expected only once every 80 to 100 years, but public conservation campaigns (with demand restraint costs in excess of $500/MWh) might be expected 1 in 20 years. Near-miss situations (similar to 2001, 2003 and 2008) are likely to occur every 5-6 years.

(f) Figure 6 shows the results of indicative analysis of spot revenues, and how this would compare with the standing costs for a new oil-fired peaker. Such a plant could expect to earn approximately $35 to $60/kW/yr from the 'normal market'. This would be 30-50% of the full cost of new oil fired reserve plant.

(g) The application of a scarcity price floor of $500-600/MWh[34] during public conservation campaigns would significantly improve the position, with expected spot market revenues equating to around 50-80% of the cost for new plant.

(h) Furthermore, even if scarcity pricing were not formally applied to actual demand curtailment, spot prices are likely to be very high in that situation. Risk aversion by wholesale buyers should mean that there is additional spot revenue not factored into this analysis. Put another way, investors in an oil-fired plant should be able to capture a proportion of the 'red' bar even without scarcity pricing.

(i) The owner of such a plant may also be able to earn some additional revenue from the provision of *capacity* (noting the above calculations are based on the revenue required to achieve the *energy* adequacy standard). As shown in Figure 1, historic analysis suggests this may equate to around $15/kW/yr.

(j) Furthermore, such plant may be able to obtain some benefit from outside the spot market, for example in the ancillary services market[35]. While this potential revenue source cannot be readily quantified, anecdotal evidence suggests that some recent 'peaker' investments have seen these other services as important sources of revenue/value.

---

[34] Noting that spot prices would be expected to go above these levels if a drought worsened following the commencement of a public conservation campaign.

[35] For example, some parties have suggested that the flexibility of peaker plants facilitates different running strategies for other large thermal units that have relatively inflexible operating ranges, leading to savings in instantaneous reserves costs.

Figure 6 – OCGT cost and inferred spot revenue components