



**Submission to the Electricity Commission
on Market Design Review Issues Paper**

From

Contact Energy Ltd

20 July 2007

Introduction

Contact Energy appreciates the opportunity to comment on the Electricity Commission's Market Design Review, Issues Paper – Survey of Market Performance (“the Issues Paper”).

The Electricity Commission has asked for comment on the performance of the existing Electricity Market. Specifically, the Review is seeking to examine the detail of the current design and identify areas that are performing satisfactorily and those where improvements can be made.

Further, the Commission has requested (in the Market Design Review conference, held 9 July) that participants to indicate the areas where they believe the Commission should focus its attention.

This paper is set out in two sections:-

- The areas Contact recommends the Commission focus on, and
- Comments on the issues raised by the Commission in the Issues Paper – i.e. Retail Market Issues, Wholesale Market Issues, Demand-Side Participation and Next Steps.

When assessing the performance of the Electricity Market it is Contact's view that the priority areas for the Commission to focus on are:-

- The Asset Owner Performance Obligations (“AOPOs”) – consistently aligning the performance obligations with the physical characteristics of varying generation technologies. (“One size does not fit all”).
- Introduction of national frequency and reserves markets
- Introduction of market based capacity mechanisms - Day ahead market and/or unit commitment

Contact notes that a significant amount of work has been done on these issues already, through various forums including the Wind Generation Investigation Project (“WGIP”), the Common Quality Advisory Group (“CQAG”) development plan and the Hedge Market Development Working Group (“HMDWG”). Contact suggests that the Commission leverage off this existing work, and recommends that a faster timetable aiming toward implementation would be advantageous to the industry.

Asset Owner Performance Obligations

It is Contact's view that the AOPOs and technical codes that should be re-considered include:-

- Frequency obligations
- Voltage Obligations
- Granting of dispensations

If new generation is unable to meet some of the AOPOs and technical codes due to physical characteristic limitations which are not easily or economically rectified, then it would seem reasonable for the Commission to review these obligations. In doing so, it would also seem reasonable for the Commission to consider the AOPOs and

technical codes in light of existing generation physical characteristic limitations, and amend the AOPOs and technical codes accordingly for these types of generators as well.

Contact considers that the existing Asset Owner Performance Obligations, Part C Section III, are biased towards New Zealand's predominantly hydro based system, and do not recognise nor make allowance for the physical differences of the multiple generation technologies we have (and will have) connected to the New Zealand Power System.

The matching of a generic rule set to a collection of generation assets all with different idiosyncrasies demands a pragmatic approach to be taken to the application of the rules, or a change to the Rules which recognises the known variances.

If a single common standard is to be applied, resulting in "non-compliant" plant having to get dispensations in order to operate, then Contact seeks an environment where all plant is treated equally to all practical extents. If a particular plant is to be granted a dispensation to the standard, because it is not practicable for it to meet a certain specification, it is important that it bears any increase in system costs arising from the need to accommodate it. Existing thermal stations already fall into this category. Any cost allocation stemming from the need to accommodate plant that has been granted a dispensation to the common standard needs to be fair and equitable and reflect actual risk. It should not be an arbitrary charge or methodology.

While the System Operator has the ability to award dispensations to "non-compliant" plant, there appears to be no recognition within the Rules that some of the AOPOs may be impossible or extremely costly to meet for particular types of generation. The imposition and allocation of "extra costs" incurred due to non performance is reasonable on the principle that the performance criterion is also reasonable (and the cost allocated reflects the incremental cost on the system).

It is widely accepted that a causer pays approach to allocating costs is crucial to achieving economic efficiency. This is just as true for intermittent generation (or any other new technology which becomes commercially viable in the NZ electricity market). The challenge continues to be in designing non-distortionary cost allocation methodologies that strike the right balance between economic purity and practicality.

How the Commission intends identifying and allocating any "extra" costs imposed by intermittent generation (or other new technologies) being connected to the system is an important part of the rule process. The Commission needs to ensure that such cost allocation is fair and equitable and be cognisant of technological limitations.

Introduction of a National Frequency & Reserves Market

Further to the Wind Generation Investigation Project May 2007 reports, Contact agrees that there is the potential for significant amounts of wind to increase the costs of frequency keeping and reserves. This is particularly the case if wind developments are concentrated in common areas where the output from adjacent installations is likely to be highly correlated.

In order that the correct economic signals are maintained to ensure that New Zealand's new generation investment requirements are achieved in an optimal fashion, it is imperative that these extra costs are borne by those who cause them –

the so called “causer pays” principle. Currently however, Contact believes the rules are inadequate in a number of respects:-

- a) If a rapid change in wind output (or any other future large scale intermittent generation technology) were to cause an under frequency event, the current rules do not adequately allow for the costs of such an event to be recovered from the causers. This is because the costs of maintaining sufficient reserves are currently only recovered from units greater than 60MW. However, it may be that a combination of a total wind farm (or 2 or 3 whose outputs are correlated) jointly cause an under frequency event.

Contact recommends that consideration be given to how the Rules (Part C, Section IV, Rule 11.5 and associated rules) could be amended to ensure that the principle of causer pays is applied. By way of example, in the CQAG development plan, one option for this is to remove the 60MW minimum altogether.

- b) It is likely that the costs of frequency keeping will increase. Contact recommends consideration should be given as to whether the +/- 50MW band needs to be increased, and how the subsequent increase in cost should be recovered. An alternative to the existing process would be to extend the frequency band, and to introduce a national frequency keeping market. Another option would be to utilise multiple frequency keepers (each of whom would be operating in the 50MW band, but the combined effect being greater than 50MW).

As noted previously, if a change in the frequency maintenance approach by the System Operator creates an increased cost to the market, then the causer of this increase should bear the cost.

Noting that there is an expectation of a need for higher levels of reserves in the future, Contact concurs with the Commission that there may be opportunities to reduce overall procurement costs for these services by gaining access to South Island instantaneous reserve. Contact supports the introduction of a national reserves market, and the development of appropriate rules to support this.

Market Based Capacity Mechanisms - Day ahead market and/or unit commitment

Investment decisions

The fact that electricity cannot be stored means that there are two “products” that need to be considered within a market framework: energy and capacity. At present, the current market design only really addresses energy, and capacity is ignored. The fact that it is not possible to selectively disconnect consumers according to whether they have contracted for capacity or not, means the provision of electricity capacity suffers from major free-rider problems. The result of this is that the market will not deliver an economically efficient level of capacity investment.

Electricity is also unusual in that it is a network commodity with two competitive activities at either “end” – generation and retail. However, there is a natural monopoly (transmission) connecting the two. Given the economies of scale of transmission, investment is such that it also suffers from major free-rider barriers.

Any investment in transmission, assuming market participants pay for transmission investments, can have significant impacts on the relative economics of generation and retail market participants.

In recent history, the focus on the “energy only” market design has not delivered good outcomes:-

- The framework for determining transmission investment was flawed with the result that New Zealand has seriously under invested in transmission. While this is being rectified, the practicality is that new transmission capacity may be built too slowly to adequately protect security of supply.
- The “energy only” market design has not provided an environment where providers of non-transmission capacity could adequately be rewarded for their investments. Similarly, with the introduction of new generation technologies, there is some risk that with no suitable market mechanism, the incentives to invest in base load capacity will be insufficient. This could make achieving security of supply more difficult.

Contact recommends that the Commission consider the development of market based mechanisms which recognise the value of capacity and deliver capacity investments and in turn overcome the free-riding problem

It is Contact’s view that a properly designed market based capacity mechanism in conjunction with a well designed transmission investment process (SOO & GIT) should deliver efficient and timely levels of investment in a manner which does not distort the market or threaten security.

Day ahead/Unit Commitment

In the more immediate term, it is Contact’s view that the introduction of large scale intermittent generation, while beneficial in some aspects, will cause adverse effects on the market and security of supply if incorrectly managed.

With the introduction of wind generation, there is an expectation that its intermittency will be offset by hydro, and that it will displace thermal generation.

Whilst it is possible that hydro plant may act in a balancing mode to counter-act the variability of wind output, such balancing may be limited, especially in certain geographical locations. Thus it is likely that the residual demand curve faced by thermal plant, once the contribution from wind is subtracted, could be much more “jagged” as depicted in Figure 63 of the Market Design Review Issues Paper. Operating thermal plant in such a fashion is less efficient and incurs more wear and tear which will be reflected in higher costs on the system. Depending on the extent of the variability, it could force CCGTs off the system as they are unable to operate in such a manner at low loads due to physical characteristics. The impact of this will have security of supply implications.

In addition the need for flexibility in plant to cope with such a jagged profile may also result in greater coal operation at the expense of more efficient CCGTs due to coal’s superior flexibility. This will have implications for overall carbon emission levels.

The industry is also exposed to unit commitment risk. If say, 8 hours out, expectations of intermittent generation are such that a thermal generator decides not to start up a thermal plant, the industry could subsequently be exposed to significant

risk if the wind does not blow. This will result in much less capacity being available on the system (both intermittent and thermal). This shortfall in capacity will potentially lead to high prices, or there being no spare capacity to help cover a contingent event. At worst, this could result in there being insufficient supply to meet demand.

Such risks are material.

Intermittent generation also brings with it a certain level of forecast inaccuracy. The impact upon participants of the additional inaccuracy in published forecast schedules, and the consequential variance in dispatch quantities and prices (sometimes at short notice) has the potential to be large.

The most visible outcome of the increase in inaccuracy will be an upward movement in wholesale electricity prices. An increase in the variation of dispatch quantities or prices will impose more costs on generators under existing rules and is likely to lead to generators setting higher marginal offers for all generation plant, whether thermal, hydro or geothermal to cover their risk exposure. The consequence will be a raft of issues including operating inefficiently for any plant (hydro, thermal or geothermal), and/or unit commitment decisions for thermal generators.

The variability will impact on participants being able to manage their risk. For a generator there will be an area of concern around the ability to manage its generation portfolio risk through unanticipated increases in intermittent (wind) generation which decreases its own real-time generation requirements and exposes it to a greater level of risk including degradation to the assets. It is also not clear whether the current rules adequately support all participants in such a situation, or whether the unit which has been displaced will be in breach of the "two hour" Rule.

Of similar concern is the unanticipated decrease in wind output, where a slow start generator did not start due to the dispatch of wind, and then the wind does not emerge. This is likely to lead to higher prices in such circumstances. This situation is more likely to result in a risk of non-supply.

Taking the above issues into consideration, it is Contact's view that the Commission should focus on developing appropriate market mechanisms, such as a day ahead market or unit commitment options to effectively manage the variability of intermittent (wind) generation. It is Contact's view that this will assist in facilitating large scale wind projects, including our own, and other intermittent generation projects becoming an integral part of the New Zealand electricity market, without negatively impacting on existing critical base load generation.

Contact asks the Commission to consider market design mechanisms which will deliver the right signals and incentives for an optimal level of development and retention of new and existing generation capacity.

Retail Market Issues

Reliability of Supply

Contact believes that the observations on reliability of supply are reasonable. The Commission's work on Electricity Security of Supply Policy Review provides a means to address some end user reliability issues. This is particularly true of setting a security margin that attempts to make the correct trade off between security and the

cost of providing security of supply. Contact believes that these other work streams provide a more focused channel through which reliability of supply can be addressed.

Other Service Quality Indicators

Contact is very focused on service quality and believes that there are strong commercial drivers for it to provide high quality energy services. Since 2004 Contact has experienced an approximate 29% drop in inbound calls per customer. Total inbound call volumes also dropped by around 31% over the same period. These statistics only tell part of the story, but they both show reductions and Contact considers that they indicate some success in delivering an improving quality of service.

Contact of course analyses its customer service and how that compares with its competitors customer service in much more detail. However this information is commercially confidential.

End User Pricing

The survey appears to be a reasonable view of assessing long run price movements and trends. Over recent decades the cross subsidies between major market segments have been gradually removed. In recent years, the reassessment of gas supply has pushed up a key cost component of electricity generation.

Gas generates up to a quarter of New Zealand's electricity - flexible and baseload generation. That flexibility is expected to remain important for a secure supply

As can be seen from Figure 1, as the Maui gas field declines, new more expensive but less flexible gas supplies are being developed.

This change in fuel flexibility may impact on how base load thermal generation plants operate. It is not clear under current market security rules how the System Operator will manage an excess of "must run" base load plant. Such plant has physical restrictions on its flexibility reflecting safe operating ranges. This will especially be a problem during low load periods such as overnight or in the summer time. Contact notes that the assumptions around the price at which thermal generation plant will switch off due to economics has yet to be tested fully in an environment where there is a surplus of fixed take gas.

Figure 1 – NZ Gas Supply Potential

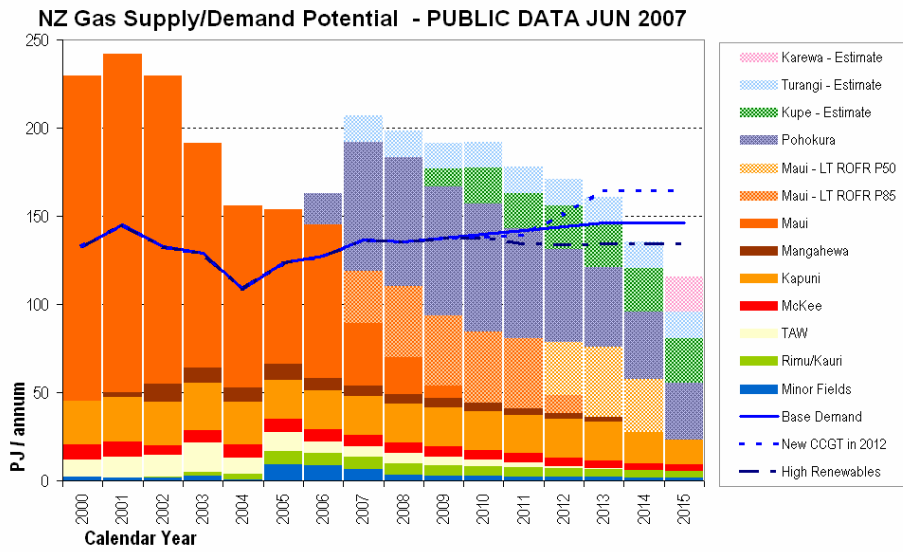
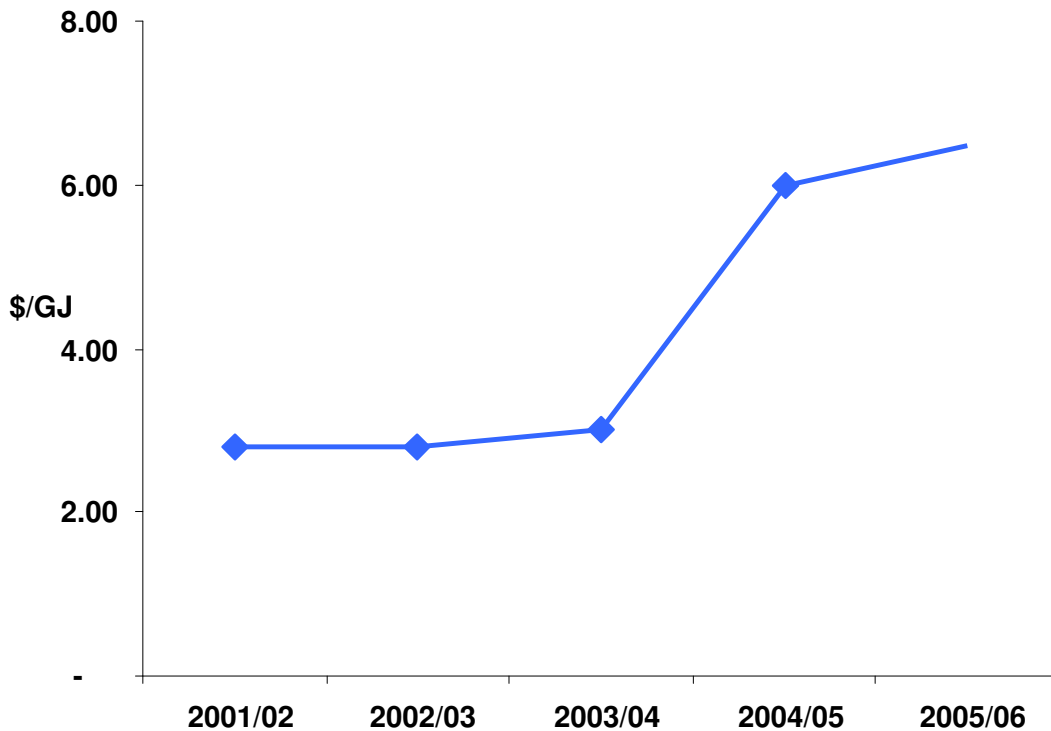


Figure 2 shows Contact’s estimate of the impact on the average price of gas as a result of changes in gas supply situation over recent years. It is an average view and does not capture shorter term price volatility that reflects short term changes in supply and demand.

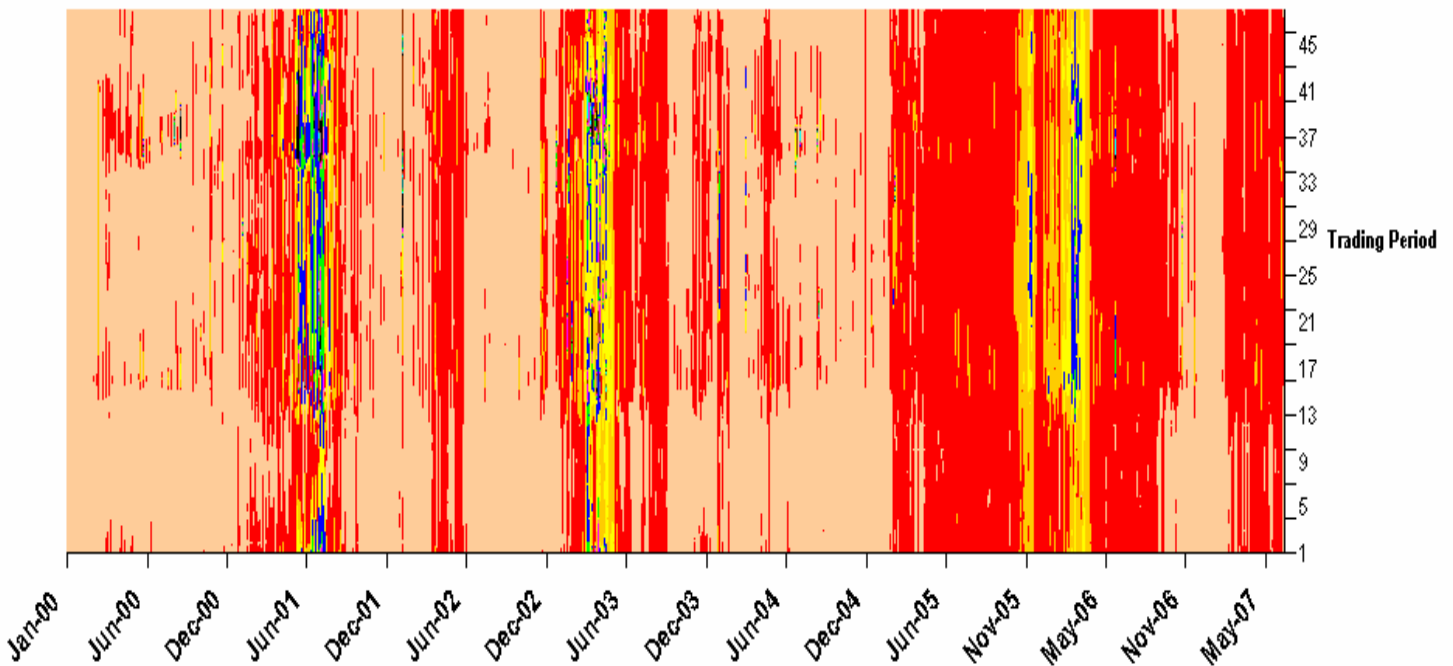
Figure 2 – Contact’s Estimate of Average Gas Price (Nominal)



Contact believes that caution is required in comparing the period prior to the introduction of the NZ electricity market and afterwards. The changes in the underlying price of gas due to the Maui redetermination will tend to distort the market reform period. In addition, the spate of dry periods since 2001 will also affect end user pricing compared to wetter sequences.

The graph in Figure 3 shows prices per trading period (on the vertical axis) since January 2000. The light pink colour is for prices <\$50, red for $50 < p < 100$, yellow/orange $100 < p < 200$ and blue for prices > 200 . The graph clearly indicates the price volatility that has been experienced by companies like Contact over recent years. The volatility is caused by such things as the 2003 redetermination of entitlements to the remaining Maui gas field, dry year issues and lack of historical capacity constraints. Electricity retailers like Contact take on the price volatility risk and package it up for their retail customers. This at least partially explains the increasing average prices for residential customers noted in the Issues Paper.

Figure 3 – Prices per trading period January 2000 to May 2007



Retail Competition Indicators

Contact notes that the lower than average churn in Tauranga could be explained by Tauranga Energy Consumer Trust's eligibility criteria for distributions. It is difficult to discern this from Figure 28 in the Market Design Review – Survey of Market Performance due to Power Co's footprint being larger than only Tauranga. However, according to the Trust's website, "To be eligible for the Cheque Distribution (year ending 31 March 2007), Consumers must have had a TrustPower account at 21 July 2006 and be situated in Tauranga City or Western Bay of Plenty areas."

The Tauranga Energy Consumer Trust's purpose on its web site is stated as: "To manage our TrustPower shareholding and other assets for the benefit of qualifying Consumers." This effectively acts as a barrier to entry. The last amount distributed was "a record \$14,835,000 to its 60,000 Consumers in September 2006." This is an average of \$247.25. "Each distribution includes a fixed sum of \$215 plus an amount based on how much power you have used in the six months to 21 July 2006."

Contact considers that there may be other localised impediments to retail competition.

Wholesale Market Issues

Supply Investment Adequacy

Contact noted in its Submission on Castalia Consultation Paper for the Electricity Commission on Electricity Security of Supply Policy Review that in Contact's view Castalia's analysis is correct - the security of supply standard of ensuring security of supply in a 1-in-60 dry year without conservation campaigns is too high. This level of security of supply has probably got to a point where the cost of avoiding tight supply conditions is higher than the expected cost of actually making voluntary savings. A standard in the region of 1-in-20 would cost New Zealand less overall, this could be made more secure by having a market that recognised the value of standby thermal stations through day ahead commitment / capacity markets. This revised standard may not be achievable if surplus New Plymouth and Huntly units were retired.

The analysis in the Market Design Review – Survey of Market Performance showing that over recent years dry year margins have averaged around 10% (higher than the target applied by the NZED, when the system was centrally planned) supports a view that the market has delivered a reasonable level of security of supply. However, significant delays in new generation projects or major reductions in capacity could make future generation adequacy tighter. This is why Contact is keen to see the Government's powers under the RMA used to good effect to ensure that projects do not get tied up for years in red tape.

Economic analysis can point to where optimal security of supply might lie. But for New Zealand to be comfortable with the level of security of supply afforded by current policy, or any change of policy, New Zealanders need a better understanding of the electricity market, the options available and the incentives of key participants. We agree with Castalia's analysis on page 45 5.3 that "Rather than adding a margin of extra conservatism to the security of supply standard, we believe that this perception problem should be addressed head-on through the publicity material that advises the market and the media about security of supply."

Possible Future Capacity Margins

Contact's position on Otahuhu C is that a decision on building the plant can be deferred. Because it is a consented site it provides a cost effective and relatively quick option to install capacity if the security margin is seriously reduced. In the meantime, Contact feels that it can focus on its geothermal and wind investments and assess whether they can provide more capacity and defer the next gas fired plant further.

Contact believes that the future investment plans of itself and others are very likely to ensure a reasonable security margin. Figures 43 and 44 in the Issues Paper are a

fair reflection of the upcoming generation potential. A combination of delays and projects dropped due to higher than planned development costs would provide a more challenging environment in which to ensure security of supply.

Contact believes that the Government's approach to security of supply using Whirinaki as a price capping plant provides poor incentives for future investors in all plant, especially peaking plant. With increasing inflexibility in gas supply and increasing amounts of wind generation entering the system, peaking plants are likely to become more important, particularly in dry years when hydro will have more difficulty covering for the unpredictability of wind generation. The economics of peaking plants are highly sensitive to a number of key variables. Because peaking plant is only run for short periods, it is critical for an investor in a peaking plant to be prepared to take on the risk that electricity prices will be high enough for long enough to pay back the investment. Contact believes that Whirinaki's short run marginal cost (SRMC) is likely to be higher than \$200/MWh Whirinaki price cap because oil prices have risen since this intervention price was set. Contact agrees with Castalia's analysis that Whirinaki's output should be priced at SRMC as this will make investment in the next peaking plant required to ensure security of supply much more likely.

Medium Term Coordination

Contact agrees with the observation in paragraph 181 of the Issues Paper that inflexible gas contracts may force thermal generators to run their plant as base load. Contact is facing this issue at the present time. This will increase the importance of hydro in dealing with volatile wind generation.

Real Time Coordination

Contact agrees that it appears that a number of trends, particularly the increasing levels of inflexible or intermittent generation on the system, will increase the challenges of maintaining supply security.

If hydro is unavailable due to dry conditions, the unpredictability of wind is likely to be an increasing concern. Of all viable renewable energy sources, wind is likely to have the largest effect on instantaneous and short-term capacity. Wind may be forecast to generate but then fail to materialise. If gas plant is not running and cold, then it will take some hours to get plant to full capacity to balance demand. Gas supply inflexibility in the future will further exacerbate these problems.

Most thermal units' availability is linked to the forecast price, which in-turn will become less accurate due to the unpredictability in wind forecasting. Since nearly all thermal units are not fast-start the possibility of having inadequate thermal generation on at any time increases with wind penetration and the most likely effect will be increased energy price volatility.

Contact's Taranaki Combined Cycle plant has a start-up time of between 3 and 12 hours, Otahuhu B has a start-up time of between 3.5 and 12.5 hours and New Plymouth has a start-up time of between 1 and 11 hours. The variation in start-up time reflects the extent to which the generation unit has been "off-line" and hence cooled down. The cold start-up time of a gas generation plant is longer, especially if returning from a long maintenance outage.

Contact notes that the slow start-up time of gas plant could be addressed by mechanisms such as introducing a day ahead market or warming contracts. These would provide energy to fill any shortfalls caused by wind's unpredictability.

Forward Contract Availability, Availability of Information on Forward Contract Prices and Comparison of Forward Contract Price Indicators

Location risk was raised by submitters to the Hedge Market Development Steering Group as a key issue. Contact believes that work on Locational Rental Allocation needs to be progressed.

Contact supports the implementation of the package of initiatives identified by the Hedge Market Development Steering Group (“HMDSG”). We consider that these proposals present pragmatic and feasible ways to address the problems identified for price risk management in the New Zealand electricity market.

The HMDSG’s approach that the primary objective should be to provide the foundation for efficient and effective price risk management among participants in the electricity market was sensible.

Contact believes that this approach will allow the emergence of hedging methods that are led by the buyers and sellers of the hedges, and thus meet their needs. In this way, the hedge market will be able to evolve over time, according to its need, and allow more opportunities for innovation. Contact agreed with the conclusions of the HMDSG that this approach is preferable to one that prescriptively imposes regulatory interventions that could be costly, fail to meet the needs of buyers and sellers, and prevent ongoing development and innovation.

The HMDSG defined its policy objective as promoting a well-functioning hedge market in contrast to the Government Policy Statement (GPS) policy objective for the hedge market is to improve transparency and liquidity. Contact believes that liquidity is not an end in itself but rather, the goal should be to enable the optimal level of liquidity to be found for the market.

Contact considers that there are characteristics of the New Zealand market that make expectations of high levels of hedge market liquidity unrealistic. Some of those characteristics are similar to those experienced by other commodity and derivative markets in New Zealand.

A liquid hedge market, by definition, requires a large volume of trades. That is, there needs to be a large number of market participants engaged in trading, as well as sufficient reason for these traders to engage in recontracting. The New Zealand market is limited in both respects.

The size of the overall market, and thus the number of participants trading, is a major limiting factor. Another key requirement for liquidity is a large volume of trading in secondary markets. Secondary market trading is a result of end users and traders striving to rebalance their portfolios, in light of newly available information. A key determinant of trading volume is therefore how, and how often, new information becomes available.

But the New Zealand electricity market contains only a small number of drivers for recontracting. Planned outages may lead to some recontracting, but unplanned outages happen too quickly, and variations in demand happen too slowly, to provide a major source of liquidity. New information about hydrology is frequent and is inherently unpredictable, but it does not generally lead to a large amount of recontracting in New Zealand, as thermal generation can act as a natural hedge against hydro variation.

Thus Contact considers that there are characteristics inherent in the New Zealand electricity system that means that the development of high levels of market liquidity is unrealistic. Contact agreed with the HMDSG’s focus on enabling “efficient and effective price risk management among participants in the electricity market,” as suggested in the discussion document.

The problems identified by the HDMSG were:

- Lack of robust information about forward prices, fuel levels, planned outages, etc
- Lack of confidence in the competitiveness of the market for term contracts
- Lack of a suitable instrument to manage locational-based or transmission price risks
- High participation and transaction costs
- Lack of understanding in the marketplace of the advantages, techniques, and uses of price risk management

Contact Energy agreed with this assessment and agreed with the HMDSG's preferred package. The HMDSG identified two initiatives in the preferred package that, in its view, would make the biggest difference in improving existing market arrangements: disclosure of contract information and changing the allocation of loss and constraint rentals.

Contact agreed that compulsory publication of contract information would be a feasible, practical way of supplying more information on risk management market activity to market participants. We noted that this is an unusual characteristic of an over the counter (OTC) market, but we supported this proposal.

Changing the allocation of loss and constraint rentals will be a more complicated proposal to implement, but Contact considered that the proposal has merit and is worth pursuing. From Contact's perspective, the debate is not between Locational Rental Allocation (LRA) and Financial Transmission Rights (FTRs). Rather, the choice is between the status quo – returning the rentals to users across the system – or pursuing an alternative allocation method that will provide a hedge against AC transmission costs.

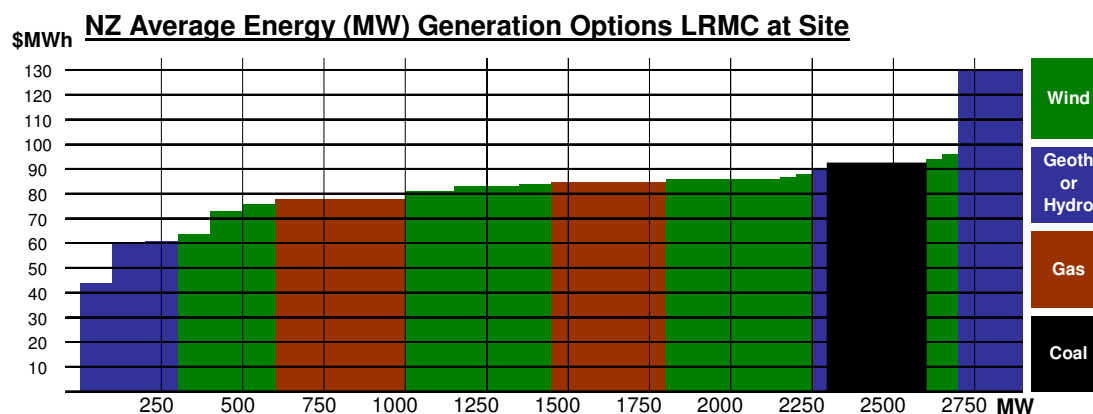
The LRA mechanism will address the lack of basis risk instruments by redistributing the loss and constraint rentals to the electricity purchasers who face the highest nodal price differences. It thus appears to be a practicable alternative that will alleviate many of the industry criticisms of previous FTR proposals, and we therefore consider that LRAs would have a higher chance of successful implementation than FTRs. At the same time, implementation of LRAs does not foreclose options for other instruments like FTRs to be developed in the future, if demand for them exists.

Contact considers that an improved allocation methodology would bring benefits to the wholesale market, in terms of enabling the management of locational price risk so we supported this proposal.

Comparison of Wholesale Prices and Estimated New Entry Cost

Contact agrees that there does not appear to be evidence that wholesale contract prices have been persistently overshooting LRMC. Contact notes that in its submission to the Government on the draft NZES it provided a view of the LRMC of a range of future generation options. This is repeated below as Figure 4. This shows geothermal projects at a lower estimated cost than estimated in the Market Design Review – Survey of Market Performance (Chapter 3-57 mid point of around \$75MWh. Figure 4 also shows wind projects that are a lot more cost competitive than Review's estimate of circa \$110MWh. Contact's estimate of the best new base load gas fired thermal generation plant, with no price on CO₂ emissions, is within the \$70-\$80 range noted by the Review.

Figure 4 – Contact's view of LRMC of all generation under AVERAGE supply conditions



Contact believes that the market is providing many competitive generation options.

Movements in Generation Capacity Share

Contact believes that the Review's analysis is reasonable.

Ancillary Services

Contact concurs with the Review that the level of competition is reasonably effective.

Frequency Keeping

Contact agrees that frequency keeps costs are linked to energy market prices. The rises in costs over time is consistent with the drivers of the wholesale market such as underlying gas prices.

However, Contact notes that the Issues Paper does not compare New Zealand frequency keeping procurement costs to any international benchmarks. Contact considers that further investigation by the Commission in this area may prove useful.

Demand Side Participation

Contact believes that the Issues Paper has provided a very good summary of the key issues that the industry faces in improving demand side participation. Contact agrees with the Issues Paper that the key issues affecting the ability of users to respond include the accuracy of forward price estimates, the degree of forward notice and the extent to which contractual relationship mute or remove price signals between the wholesale market and the end-user.

Real time demand side participation

Real time demands side participation is problematic for commercial and residential customers, however as noted in paragraph 330 of the Issues Paper, technological change, such as from the rollout of smart meters may alleviate some difficulties in this area. In the future, Contact expects that it too will have widespread deployment of smart meters to its retail customers. With the widespread deployment of smart

meters, it is likely that new tariff options and web-based tools will be developed, so customers can analyse historical information on their power use and adjust their price plans or demand accordingly.

Next Steps

Contact reiterates that it welcomes the opportunity to submit on the Commission's Market Design Review and looks forward to the next steps in the process when the suggestions made in this submission are evaluated by the Commission.