MINISTRY OF BUSINESS, INNOVATION & EMPLOYMENT
HĪKINA WHAKATUTUKI

Ref: DOIA 2324-2099

16 April 2024

Privacy of natural persons

Tēnā koe Privacy of natural persons

Thank you for your email of 25 March 2024 to the Ministry of Business, Innovation & Employment (the Ministry), requesting the following under the Official Information Act 1982 (the Act):

> *The final report of the 2009 Electricity Market Review. The report is referenced in https://www.beehive.govt.nz/release/ministerial-review-electricity-market and section 108 of https://www.mbie.govt.nz/dmsdocument/178-chronology-of-nz-electricity-reform-pdf*

We believe the final report of the 2009 Electricity Market Review is the attached report titled: *Improving electricity market performance: Summary note on recommendations taking account of submissions* dated October 2009. I have decided to release this to you in full.

If you wish to discuss any aspect of your request or this response, or if you require any further assistance, please contact OIA@mbie.govt.nz.

Please note that this response and enclosed document, with your personal details removed, may be published on the MBIE website: https://www.mbie.govt.nz/document-library/

You have the right to seek an investigation and review by the Ombudsman of the Ministry's decision to withhold information relating to this request, in accordance with section 28(3) of the Act. The relevant details can be found at: www.ombudsman.parliament.nz.

Nāku noa, nā

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Improving electricity market performance

Summary note on recommendations taking account of submissions

This note summarises consideration by ETAG and the Ministry of Economic Development on submissions on the preliminary recommendations in the discussion paper "Improving Electricity Market Performance"[1] released on 12 August 2009. The material in this paper formed the basis of a Cabinet paper on the Ministerial Review of the Electricity Market.

October 2009

[1] http://www.med.govt.nz/electricity-market-review

Main general comments on the discussion document [2]

- Business NZ, NZCID, Chambers of Commerce, MEUG, major users: Should be more focus on the productive sector and the needs of business.

- Several submitters, including Business NZ, NZCID, Contact, Vector: Should be clearer/better specification of desired market outcomes and performance indicators for the sector.

- Domestic Energy Users Network (DEUN), Age Concern, AECT and others (including individuals). Should be much more focus on residential consumers, low income consumers, and energy poverty. Need to consider 'firm regulation' (eg price control). Need to retain focus on fairness and affordability.

- Many submitters: need for more detail and analysis relating to recommendations, and a further round of consultations.

- Many submitters: need a (mandatory) further review in 2 or 3 years, or 3 - 5 years

- Consumer NZ: 'last chance' for the competitive market.

- Contact and Genesis: contest the view that prices / retail margins are too high. See comment in Appendi9x A.

- MEUG: disagree with apparent dismissal of Wolak report, and use of LRMC to asses market power

- Unison and others: report focuses too much on current technologies. Review should be more focused on smart grids, empowered customers and more small-scale DG. Distributors should have a central role in this new world.

- Energy Centre: need better analysis of root causes: the main one being insufficient dry year 'capacitance'

- Bryan Leyland. Much more thorough-going review and analysis required. Report justifies excessive prices / profits. Current market is fundamentally flawed and should be replaced by a 'single buyer' model.

- Others (general): Review lacking in a strategic vision; has information gaps; doesn't take current global environment (eg climate change) into account; recommendations will fail to fix the real problems.

- Number of groups and individuals: need more assistance for energy efficiency and renewables.

- EC: many of the recommendations are being addressed through its current work programme, specifically:

    - Scarcity pricing
    - Reserve energy and Whirinaki
    - Locational hedges
    - Market monitoring

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[2] See also comments on alternatives to asset swaps (recommendation 17).

- Transmission pricing
- Distribution pricing
- Demand-side initiatives
- Advanced meters
- Improved ancillary services.

To improve security of supply

Recommendation 1

Require retailers to make payments to consumers in the event of a public conservation campaign or enforced power cuts, with a graduated scale reflecting the level of nationwide savings (as determined by the System Operator), and with a minimum payment of, say, $10 per week.

1. Reason for recommendation

- To remove the incentive on market participants exposed to spot prices (eg over-hedged generators and under-hedged retailers and users) to push for conservation campaigns (which shift costs on to consumers and create a sense of crisis and insecurity)

- To improve incentives on generator-retailers to manage security of supply risks (eg better water management, better hedging, building dry year generation plant, rewarding demand-side management), by imposing a cost for resorting to public conservation campaigns.

- To make public conservation campaigns, when required, more acceptable to consumers.

2. Submissions

- Many submitters (particularly consumer groups, plus Genesis and MRP[3]) agreed with the recommendation without significant reservation.

- Many submitters supported in principle, but were concerned about design detail:
  - View that the funding should come from generators that had mismanaged their fuel (water) resources or retailers who were under-hedged.
  - Concern that all retailers (including independent retailers) would be penalised including those which had properly managed their risks eg by being fully hedged
  - View that only consumers making savings should benefit

- Major users (MEUG and major users) considered payments should also go to larger users (not just residential and small business consumers)

- Trustpower opposed, but advocated, if it was introduced, an exemption for retailers who provided a choice of tariffs (‘with and without compensation’) for consumers.

- Some submitters (eg Orion and Vector) opposed, on the grounds of perverse effects and risks (in addition to the targeting issues noted above):
  - Pushes up risk premiums for retailers and therefore prices
  - Increases barriers for new entrant retailers (such as lines businesses) because of additional risk of having to make pay-outs
  - Risk that retailers would be disincentivised from supplying smaller, low-margin consumers
  - Risk that market participants would delay calling a conservation campaign until it was too late

[3] MRP’s support was conditional on an exemption for retailers who had their own consumer compensation scheme (as proposed in the discussion document)

- o Reduces likelihood of retailers running targeted campaigns rewarding individual consumers (which are complex and costly) because they are faced with payout costs anyway

- The EC noted that it was putting out a discussion paper on compensation issues in October.

3. Key issues

- Do the perverse effects and risks of a simple compensation scheme outweigh the benefits?
- Would better design (eg funding to come from generators which have run out of water; rewarding only consumers who save) reduce the dis-benefits sufficiently? Would better design be too complex?
- Will other measures (eg floor on spot prices) be sufficient to realise the benefits?

4. Comment

- Targeting (eg of generators which have run short of capacity, under-hedged retailers etc) is too complex
- Note that even well-hedged retailers benefit from a public conservation campaign (reduces demand, thereby providing a cash benefit on unused hedges and/or sale of excess hedges)
- Note also that the EC is shortly releasing a paper which inter alia covers this issue: it is understood to support universal cash compensation payments to consumers during conservation campaigns (where the retailer is not offering targeted buy-back rewards).

5. R90ecommendation

Require retailers to make payments to consumers in the event of a public conservation campaign and enforced power cuts.

To improve security of supply

Recommendation 2

Put a floor on spot prices during any public conservation campaign or during any enforced power cuts in a dry year of, say:

- o $500/MWh (50c/kWh) when a public conservation campaign is activated
- o $1,000 - $5,000/MWh ($1 - $5/kWh) if and when forced power cuts are activated.

1. Reason for recommendation

- To remove the incentive on market participants exposed to spot prices to push for conservation campaigns
- To improve the incentive on market participants to better manage dry year risk.

2. Submissions

- Some support (eg Contact, Genesis), including for further investigation and analysis (MEUG, Federated Farmers, NZ Steel).
- Regarding the floor price, Genesis noted that it is more important to give certainty than strive for theoretical perfection. It recommended floor prices be set in legislation
- Many submitters supported administered VOLL (value-of-lost-load) pricing during forced outages, but opposed floor prices during a public conservation campaign
- Most submitters opposed recommendation 2.1 (floor price during conservation campaigns) on a range of grounds, eg
  - o Risk of upward pressure on prices
  - o Disincentive for new retail entry
  - o Penalises spot purchases by major users during a conservation campaign in the absence of a more liquid hedge market, which may affect export orders (CHH, Pan Pac)
  - o 'Unique [in the world] and untested'. Should be a cap on prices, not a floor.
  - o May delay undertaking conservation campaigns (but a campaign may be efficient and necessary).
- Note: much of the opposition[4] was on the grounds that a floor price would result in inefficient/uneconomic despatch of generation (including uniform nodal prices) and would reward generators for running out of water where prices would otherwise be lower than the floor. *However, inefficient despatch is not expected to be an issue[5].*

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[4] Eg, MRP, Trustpower, Todds, Energy Centre, CHH,

[5] Two alternatives are available:
(i) generation would continue to offer to be despatched and be paid the clearing price. Only purchasers would face the floor price, or
(ii) offered generation/supply would receive a spot price adder so the clearing price reaches the floor price

- The EC noted that (a) it agreed with the objective, and (b) it is currently consulting on this option (scarcity pricing).

3. Key issue

- Much of the opposition seems to be based on a misconception (inefficient despatch)

- This option is well targeted because it impacts only on parties which have not managed risks and need to buy on spot when prices are very high (eg generators which have run out of generating capacity to meet their supply obligations or retailers/users which are under-hedged).

4. Comment

- Keep the recommendation but remove specific numbers

- Implementation: legislation to provide power[6] for the Minister to make rules on this issue if the EMA does not adequately address it within a reasonable (prescribed) timeframe.

5. Recommendation

> Put a floor on spot prices during any public conservation campaign or during any enforced power cuts in a dry year.

[6] Note: this would be a "*may*" power, not "*must*".

To improve security of supply

Recommendation 3

Clarify roles and responsibilities for security of supply (as set out in Table 2 on page 21).

1. Reason for recommendation

- To provide for role clarity on responsibilities for security of supply

2. Submissions

- Wide support.
- Transpower noted the importance of the EMA setting the rules impacting on security of supply
- Several submitters (eg MRP, Meridian) noted that the Minister should not trigger public conservation campaigns and forced outages: rather his should be done by the EMA according to pre-set and clear criteria (eg hydro levels and shortage probabilities), to provide certainty.

3. Comment

- Agree that triggering public conservation campaigns and forced outages should be done by the EMA according to pre-set criteria.

4. Recommendation

Clarify roles and responsibilities for security of supply.

To improve security of supply

Recommendation 4

Phase out the reserve energy mechanism, and reassign the Whirinaki power station to an SOE or sell it.

Recommendation 5

Alternatively, if the Government wants to retain the reserve energy mechanism as a backstop, then it should:

- o Reassign Whirinaki to an SOE or sell it.
- o Ensure that a mechanism is developed (such as a surcharge on spot prices) through which parties that benefit from any reserve energy when it is called on (that is, parties that are exposed to spot prices) contribute to the standing costs of that reserve energy.

1. Reason for recommendation

- The reserve energy scheme has unintended and perverse effects including:
  - o Reducing incentives on market participants to manage their own risks (because the EC is expected to manage those risks as a last resort)
  - o Reduces the incentive for investment in peaker plants and for demand-side responses
  - o Incentivises lobbying to change the rules relating to reserve energy (eg for despatch of Whirinaki), creating uncertainty.

- Whirinaki's location (and diesel fuelling) is sub-optimal

2. Submissions

- Virtually unanimous support for recommendation 4

- Strong support for selling Whirinaki (for operation in New Zealand) rather than assigning it to an SOE. (Business NZ: if it is not possible to sell Whirinaki prior to winter 2010 it should be operated on a fully commercial arms-length basis in 2010).

3. Key issues

- If Ministers accept the recommendation there will be a large number of administrative issues to be considered (including whether or not the Crown wants to recover any deficit between its fixed costs and the sales price)

- Note (confidential): officials understand that Meridian and Genesis have entered into a 5 year contract which provides for Genesis to keep Unit 4 at Huntly available for reserve generation. (This removes any need for the EC to contract for reserve capacity).

4. Comment

- In light of submissions, drop recommendation 5.

- If Whirinaki is re-assigned, it should be to either Meridian or Mighty River Power, because Genesis already has a large position in thermal generation.

5. Recommendation

Phase out the reserve energy mechanism, and sell or re-assign the Whirinaki power station (for operation in New Zealand).

To improve security of supply

Recommendation 6

Require SOEs to disclose their risk positions and other relevant information in the same way as private sector companies listed on the Stock Exchange, to improve the quality of information available on risk and sharpen risk management incentives.

1. Reason for recommendation

- To provide for a better informed marketplace, and improve incentives on SOEs to manage risks

2. Submissions

- Wide agreement

- Some SOEs considered that the disclosure requirements should be determined in a protocol with shareholding Ministers and noted that such a protocol was in the process of being developed

- Many submitters (especially Business NZ, MEUG) argued that the disclosure requirements should:
    - apply to all generators (including listed and privately owned)
    - be based on disclosures required to benefit the economy and the efficient operation of the market (cf NZX rules which aim to inform investors)

- The EC noted that it is working on additional disclosure rules as part of its Market Development Project.

3. Comment

- Disclosure should be based on electricity market requirements (cf investor requirements) and apply to all generators. This will help encourage good hedging practices.

4. Recommendation

Require all generators above a certain size, including SOEs and listed and privately-owned companies, to disclose information (such as hydro reserves, fuel stockpiles and availability, planned outages and historic net hedge positions) which informs the marketplace on supply risks and management of risks.

To improve security of supply

Recommendation 7

Investigate developing terms and conditions for accessing 'reserve water' in lakes in dry year emergencies which cap benefits to generators and provide for compensation to affected communities and mitigate or avoid environmental effects.

1. Reason for recommendation

- To provide better management of hydro lakes and environmental risks and to reduce the risk of ad hoc responses under emergency conditions.

2. Submissions

- Most submitters considered that this issue merited further work, and that there would be benefits from greater certainty and clear criteria, although:
  - Trustpower noted that any new terms and conditions should not override existing arrangements
  - Meridian considered that terms and conditions should be set in an RMA framework
  - Business NZ, Federated Farmers and MAF noted that it was important to consider competing uses of water, such as irrigation
  - Pan Pac noted that minimum water flows in emergencies also needed changing

- Some submitters (eg Guardians of Lake Manapouri, ?) opposed

- Contact was unenthusiastic and preferred to use the RMA.

- NZ Centre for Infrastructure Development (NZCID) noted the limitations of the RMA framework since the benefits of access to reserve water were nation-wide while the costs and impacts were local.

3. Issue

- Which lakes should be included: all potential reserve water or just the key lakes with reserve water (Pukaki and Hawea)?

4. Comment

- Undertake a detailed review focused on Pukaki and Hawea.

5. Recommendation

Invite the Minister of Energy and Resources and the Minister for the Environment to report back by end March 2010 on whether and if so how, terms and conditions should be set in a dry year emergency for access to water below normal consent levels in Lake Pukaki and Lake Hawea.

To help restrain the costs of generation

Recommendation 8

Ensure, when making decisions on climate change policy, that full weight is given to the importance of providing certainty for investors including, to the extent possible, providing for stability and predictability on the future cost of carbon and other emissions.

1. Reason for recommendation

- To improve certainty for investors

2. Submissions

- Wide agreement
- MAF (not a public submission) argued that it was not possible to provide for predictability of the price of carbon since it is set internationally.

3. Issue

- Given the recently announced decisions on the ETS, it is debatable whether there is value in a recommendation on climate change.

4. Comment

- Make a noting recommendation (for the sake of completeness) regarding the effects of climate change policy.

5. Recommendation

Note that climate change policy settings, the future cost of carbon and other emissions, and uncertainty on these issues, will have a significant impact on the cost of generation and on investment decisions.

To help restrain the costs of generation

Recommendation 9

Ensure that the current reviews of the Resource Management Act and water allocation consider:

9.1 Whether and how the ‘call-in’ process could be used to better effect for generation projects (new and existing).
9.2 Other fast-track mechanisms for consenting (or re-consenting) nationally significant generation projects.
9.3 Providing for water and geothermal rights to match the life of the assets.
9.4 Whether certain types/sizes of generation could be deemed to be a permitted activity in predefined circumstances and areas.
9.5 The terms for consents, particularly the lapse provisions, to better recognise the nature of large-scale generation investment projects.
9.6 Whether powers such as compulsory acquisition of land, with appropriate compensation provisions, should be available for nationally significant generation projects.

1. Reason for recommendation

- To reduce the costs, delays and uncertainties for generation relating to RMA processes
- To ensure that the current review of water allocation adequately considers hydro generation

2. Submissions

- Wide agreement from market participants
- Some submissions (eg, Federated Farmers, Business NZ, and Consumer NZ) noted that it was important not to erode the RMA rights of other parties.
- The NZCID recommended a NPS on generation.
- Contact advocated an additional recommendation to the effect that water allocation policy should not undermine existing and future hydro generation.

3. Comment

- MfE has noted that the first two issues have been addressed in the recent amendments to the RMA.
- There is a need for considering how best to give national direction on the importance of hydro generation in water allocation decisions.

4. Recommendation

Invite the Minister for the Environment to ensure that the current reviews of the Resource Management Act (second round) and water allocation consider:

- Providing for water, wind and geothermal rights to match the life of the assets

- Whether certain types/sizes of generation could be deemed to be a permitted activity in predefined circumstances and areas

- The terms for consents, particularly the lapse provisions, to better recognise the nature of large-scale generation investment projects

- Whether powers such as compulsory acquisition of land, with appropriate compensation provisions, should be available for significant generation projects.

Consider how best to provide national direction on the importance of hydro generation in water allocation decisions.

To help restrain the costs of generation

Recommendation 10

Ensure that the current petroleum resources review takes full account of the importance of gas to electricity generation using existing or new assets.

1. Reason for recommendation

- Gas is a critical fuel for electricity generation, with around 25% of electricity typically generated from gas. It has a major influence on both short-run costs and the cost of new capacity.

2. Submissions

- General agreement (or no comment)

- Contact noted that:
  - o Gas-fuelled power stations play a critical role in backing up less certain sources of generation, particularly hydro
  - o It is a premium fuel, providing flexibility for short-notice generation and lower emissions than other thermal generation
  - o While it appears that sufficient gas will be available for the next ten years, supply is not sufficiently certain to support the construction of new gas-fired plant. Both Contact and Genesis have deferred plans to build new gas-fuelled generation
  - o Unless substantial new fields are found a decline in the availability of electricity generated from gas is inevitable as existing plant nears the end of its economic life
  - o The drive for increased generation from renewable sources such as wind and hydro increases the requirement for back-up thermal generation to maintain security of supply

3. Comment

- MED is currently considering policy options for improving investment in petroleum exploration activity, improving knowledge of frontier acreage and ensuring maximum gains from New Zealand's petroleum resources. The Minister of Energy is expected to ensure that full account is taken of the importance of gas for electricity generation.

4. Recommendation

Note that the Minister of Energy is developing recommendations on policy options with regard to petroleum resources, and that the recommendations will take full account of the importance of gas to electricity generation using existing and new assets.

To help restrain the costs of generation

Recommendation 11

Improve the quality of published information on gas reserves.

1. Reason for recommendation

- To provide more certainty for the marketplace on the reserves situation, given the critical importance of gas to the electricity market.

2. Submissions

- General agreement:
  - o Genesis noted that gas is a Crown-owned resource, so it was reasonable for the Government to require disclosure (and publication) of top quality information
  - o Todd Energy agreed, to counter the “varied, conflicting and often misinformed views currently represented in the public arena”. Note however that Todd Energy considered that MED already has the necessary information.

- Contact and Genesis made specific proposals on the information required (p37 and p11 respectively)

- PEPANZ said it was unsure what is deficient with the current information.

3. Comment

- MED proposes to undertake a project with the following objectives:
  - o Develop an understanding of recent reserve fluctuations
  - o Identify upside potential at existing fields (i.e. P10 and contingent resources)
  - o Identify all “near term” resources
  - o Assess future gas supplies in the short-medium term based on the identification of all known leads being pursued in the Taranaki and Northland Basins
  - o Evaluate the current legislative and regulatory framework around gas reserves, and
  - o Identify policy options that would improve the quality of gas reserve information

4. Recommendation

Note that the Minister of Energy and Resources has directed the Ministry of Economic Development to report to him by 31 March 2010 the Economic Growth and Infrastructure Committee by 18 November 2009 on measures to improve the quality of published information on gas reserves.

To help restrain the costs of generation

Recommendation 12

Identify barriers to the development of geothermal energy which can and should be addressed by the Government.

1. Reason for recommendation

- Geothermal is generally considered to provide the most economic tranches of new generation for much of the coming decade, so it is important to ensure there are no barriers to development.

2. Submissions

- Contact and MRP considered there are few if any barriers.
  - Contact said that the wider RMA issues are the only matters that need addressing.
  - MRP said it would be a serious error to introduce licensing

- Genesis observed that it would be problematic if "one or two developers" had a tight hold on the resource as it would enable them to price output from the new plant up to the cost of the next best alternatives. Contact said there were plenty of parties involved in geothermal development.

- Rio Tinto advocated that more local authorities should follow the lead of Environment Waikato and pre-designate areas suitable for geothermal development.

3. Comment

- MED is currently undertaking a review of geothermal resources. It is considering the full breadth of geothermal resources including ground source heat pumps to enhanced geothermal systems throughout New Zealand.

4. Recommendation

Note that MED is undertaking a review of barriers to the development of geothermal energy which can and should be addressed by the Government, and will report to the Minister of Energy and Resources by April 2010.

To help restrain the costs of generation

Recommendation 13

Consolidate responsibility for the promotion of energy efficiency in EECA, and remove it as a responsibility of the electricity regulator, while:

13.1 Carrying out a strategic review of EECA to ensure it is well-focused and performing effectively.
13.2 Transferring best practice approaches developed by the Electricity Commission where possible
13.3 Reviewing funding for EECA, with a general principle that funding should be through levies where the beneficiaries can be clearly identified and administrative (collection) costs are low.

1. Reason for recommendation

- To remove the duplication of two Government bodies undertaking promotion of energy efficiency, and to improve the delivery of energy efficiency promotion generally.

2. Submissions

- Fairly wide agreement to consolidating energy efficiency promotion in EECA

- However, there was some support from the energy efficiency industry for the EC/EMA to retain energy efficiency programmes.

- The EC noted that it had developed best practice approaches to energy efficiency promotion, including “commercial partnerships and performance-driven contracts”

- Nearly all market participants argued that funding for promotion should be taxpayer funder, not levy funded. This was particularly the case because there are multiple benefits from energy efficiency including better health outcomes and environmental improvement as well reduced demand and improved household incomes. It was noted that the Insulation Fund initiative was taxpayer funded.

- Business NZ and MEUG argued that if the Government nonetheless decided to retain levy funding, major users should be exempted, because (i) they already have a strong incentive to improve energy efficiency and (ii) the beneficiaries of energy efficiency promotion are primarily households.

- Many submitters commented on the need for transparency and increased accountability for levy-funded activities.

3. Comment

- Note that providing an exemption for major electricity users raises boundary issues. Also, all users (including major users) benefit from improved energy efficiency by other users/consumers, since demand reduction and load shifting reduce spot prices compared to otherwise.

4. Recommendation

Consolidate responsibility for the promotion of energy efficiency in EECA, and remove it as a responsibility of the electricity regulator, while:

1. Carrying out a strategic review of EECA to ensure it is well-focused and performing effectively

2. Transferring best practice approaches developed by the Electricity Commission where possible. This should include a requirement to consult with levy payers on programme proposals

3. Reviewing funding for EECA, with a general principle that funding should be through levies where the beneficiaries can be clearly identified and administrative (collection) costs are low.

To help restrain the costs of generation

Recommendation 14

Review whether there are likely to be net benefits, compared to alternatives, in developing a National Environmental Standard for small-scale distributed generation, such as solar photovoltaics, micro-wind turbines and solar water heating panels.

1. Reason for recommendation

- To reduce the time and costs of obtaining resource consents for small scale generation.

2. Submissions

- Many submissions (eg Meridian, Contact, RTNZ, Genesis, and Vector) supported a review.

- Several submissions (eg Orion, MRP, Powerco) did not object but expressed scepticism that there would be worthwhile benefits
    - Powerco highlighted the complexities of the issues and the range of different technologies with differing environmental effects

- Todd supported but said the threshold should be increased to <25MW

- MAF (not public) and Refit advocated that mandatory feed-in tariffs should be developed for DG.
    - 'Feed-in' tariffs are widely used overseas to require retailers to buy electricity at above-market rates as an incentive to investment in (renewable) DG. (This is often part of a climate change response: NZ's approach has been to focus on an ETS to feed into prices generally).
    - Several submitters also advocated 'net metering' or 'net billing', whereby retailers are obliged to buy at the same price at which they sell.

3. Comment

- EECA has advised that:
    - It already undertakes extensive work on distributed generation
    - It has promulgated voluntary guidelines for local authorities, which work well
    - It is not convinced of the need for an NES: most small-scale D-G is subject to significant technological evolution, and/or its presence in NZ is minor
    - It would be very difficult to do an NES, it could rapidly be out-of-date, and it could be counter-productive (leading to undesirable restrictions).

- Agree with EECA (and MfE) that it is unlikely to be worthwhile developing an NES for small-scale DG, and that undertaking a review on this issue is not a priority at this time.

- Agree that work needs to be done on the terms and conditions for selling surplus output from small-scale DG to retailers (not least to reduce the transaction costs of individual DG investors negotiating with retailers). The extent to which prices contain a subsidy

[7].

- o Note that this issue will become more important as electric cars become more widely used.

4. Recommendation

No recommendation on developing an NES for small-scale DG

The EC/EMA should be requested to develop, in consultation with EECA and interested parties, terms and conditions for the purchase by retailers of surplus output from small-scale distributed generation.

[7] Some submitters argued that solar PV reduces the need for network upgrades. It is not clear this is the case, because solar PV does not generate electricity when there is peak load on networks (unlike many overseas countries when peak load – for air conditioning - occurs during daylight hours).

To improve procedures for upgrading transmission services

Recommendation 15

Amend the Grid Investment Test to make it clearer, simpler and less prescriptive, and to take into account wider competition benefits.

1. Reason for recommendation

- To improve the Grid Investment Test (used to consider whether grid upgrade proposals should be approved)

2. Submissions

- Many parties (eg Business NZ, Vector, NZCID) thought the GIT should be amended, but wanted to see the detail first

- Generators and Transpower generally advocated a change in the GIT to facilitate faster and easier approvals of grid upgrades. They were generally critical of the EC's approach of "shadow grid planning" and considered that speedier and easier approvals were essential
    - o Meridian wanted guidance on the GIT to be provided in legislation

- MEUG and other major users (Rio Tinto) were generally cautious about relaxing the criteria, and considered that only quantified benefits should be included. They noted that it was not surprising that generators advocated an easier test because they did not pay for AC upgrades. (Rio Tinto said that the EC had "shaved hundreds of millions of dollars off Transpower's proposals")

3. Comment

- Responsibility for specifying the test for grid upgrades should be transferred to the CC, along with approvals of grid upgrade proposals. The CC should use the Part 4 (Commerce Act) purpose statement in developing the test. The test should be set as an "input methodology" under Part 4 (which makes it subject to merits review).

4. Recommendation

see recommendation 27

Recommendation 16

Transfer approval of major grid upgrades to the Commerce Commission to ensure integrated consideration of transmission expenditure, performance and prices, subject to rules on service and reliability standards, pricing methodologies and the grid investment test set by the electricity regulator.

See recommendation 27

To improve wholesale and retail competition and help restrain prices

Recommendation 17

Subject to further analysis following submissions, restructure SOE assets, by either:

17.1 Option One: Create a new SOE generator-retailer comprising the Huntly and Manapouri power stations, and, additionally, transfer Tekapo A and B to Genesis and Whirinaki to Meridian.
17.2 Option Two: Transfer the Huntly power station to Solid Energy, the Manapouri station to Genesis and the Whirinaki station to Meridian.
17.3 Option Three: Transfer the e3p and P40 power stations from Genesis to Meridian and the Manapouri power station from Meridian to Genesis.

1. Reason for recommendation

- To improve the level of competition:
  - o in retailing, particularly in the South island
  - o in the wholesale market, particularly in dry years.

- Ministers have ruled out options one and two

- Option Three is intended to create:
  - o A third main generator in the South Island (improving wholesale market competition, but particularly retail competition in the South island, since generators focus their retailing in regions where they have generation assets)
  - o A third main thermal generator (providing some improvement in wholesale market competition, especially in dry years)

2. Submissions

- <u>In favour (generally strongly)</u>: Genesis, MEUG, Rio Tinto, CHH[8], Norske Skog[9], Pan Pac, Energy Link, Wind Farm Developments, Todd Energy[10]
  - o MEUG noted that Standard and Poors had concluded that asset swaps would put generators under more competitive pressure (ie that the objective of the swap would be realised)
  - o Rio Tinto advocated a revised Option Three, with the Lower Waitaki stations (Benmore, Aviemore and Waitaki) going to Genesis, and e3p and p40 going to Meridian[11].
  - o Genesis supported Rio's proposal, or, as an alternative, proposed it should acquire Tekapo A and B (with no assets going to Meridian)

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8 CHH supported option two (Huntly to Solid Energy)

9 Norske Skog supported Huntly going to Meridian, rather than e3p and p40. The Energy Centre made a similar recommendation.

10 Todd Energy considered that asset swaps would improve the depth of the gas market.

11 Rio noted that its agreement for any asset swaps involving Meridian was required under the Tiwai point contracts. It said it would not support Option Three as specified, because Manapouri is closely tied to supply to the smelter. (This also meant, inter alia, that if Genesis acquired Manapouri it would have little net capacity to support a retail presence in the South Island).

- Energy Link supported Tekapo A and B going to Genesis[12]
  - *Note: no support for transferring Manapouri to Genesis*

- Provisionally support, subject to a detailed and positive CBA and proven competition benefits: Wood Processors Assn, Employers and Manufacturers Assn, Business NZ, Federated Farmers, Network Tasman, Uni Auckland PSG, Consumer NZ

- Generally opposed or sceptical: Meridian, MRP, Chambers of Commerce, NZCID, Contact, MRP, EC, Orion, Vector, Powerco
  - General view that benefits had not been proven (more analysis required) and/or were unlikely to exceed costs (including disruption and time to implement)
  - Widespread view that either:
    1. other measures recommended in the paper to promote competition were sufficient[13] and/or should be tried first[14], or
    2. there were better measures (not recommended in the Review) that should be adopted instead (see next section).
  - Transpower (not public) considered that although the original SOE asset configuration was sub-optimal, the benefits of asset swaps now are unlikely to exceed the costs.

- Other measures advocated as a better approach than asset swaps (particularly to get a more liquid hedge market[15])

  - Contractual arrangement between SOEs to mimic the outcome of asset swaps ('virtual power plant' contracts). (Fonterra)

  - Compulsory futures trading on a NZ futures exchange. (Meridian, NZX, Powershop)

  - Mandatory offering of hedges by generators (as discussed in Appendix 20). (Todd, Fonterra, Powerco, Vector, NZX)

  - Separation of generation and retailing. (Vector, CHH, Norske Skog, Fonterra, Unison)

  - Replace nodal pricing with zonal pricing. (Rio Tinto and other major users).

3. Comment

- Issue needs further consideration. See separate notes (Appendix B) reviewing:

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[12] It said that Lake Pukaki provided sufficient storage to buffer inflows from the Tekapo system in all but extreme flood conditions.

[13] Meridian, Genesis and MEUG (despite disagreeing on asset swaps) were in agreement that this was not the case. Genesis noted that transmission upgrades and transmission hedging will reduce the severity of basis risk (locational risk) but not eliminate it, and, for that reason, retailing activity will continue to follow asset bases.

[14] Several submitters (including Business NZ) argued that there was an 'option value' in waiting to see if other measures proved sufficient to improve the level of competition, and only proceeding with asset swaps if problems remained.

[15] Several submitters argued that asset swaps would not necessarily deliver an on-going improvement in hedge market liquidity, because the generator-retailers would soon settle back into an equilibrium of roughly balanced generator-retailer portfolios. They noted that this would not assist new entrant retailers (such as lines companies).

- o Alternative asset swap proposals by Rio Tinto (split the Waitaki stations) and Genesis (Tekapo A and B)
- o A one-off long-term contract between the three SOEs (‘virtual asset swap’)
- o Compulsory futures trading (Meridian proposal)
- o Compulsory offering of hedges.

- Consideration needs to be given to specific measures to improve hedge market liquidity.

- Mandatory separation between generation and retailing is not likely to have net benefits, for the reasons given in the discussion paper (increased transaction costs and riskiness and cost of capital of both generation and retailing).

- The difficulty with the argument that nodal pricing should be done away with, is that the value of generation and demand-side response differ values depending on location. Market design options do not make that issue go away. If locational differences are not reflected in spot prices, another mechanism is required to provide the necessary incentives to reward generation and demand response in areas of tighter supply. Any alternative is likely to be less efficient than nodal pricing.

4. Recommendation

- The following recommendations were developed following consideration of submissions, the matters covered in Appendix B and discussions with the Minister. Refer Cabinet paper for discussion.

- Re-balancing SOE assets

1. Tekapo A and B power stations to be transferred from Meridian Energy to Genesis Energy and the government-owned Whirinaki plant to be sold to Meridian Energy. (Majority support from ETAG, with the balance considering that the option is worth serious consideration).
2. Meridian Energy, Genesis Energy and Mighty River Power to undertake ‘virtual asset swaps’ involving one-off long-term (15 year) contracts as follows:
   - Meridian Energy to sell 1,000 GWh/year of ‘South Island’ energy to Mighty River Power, and buy 1,000 GWh/year of ‘North Island’ energy from Mighty River Power
   - Meridian Energy to sell 450 GWh/year of ‘South Island’ energy to Genesis Energy, and buy 450 GWh/year of ‘North Island’ energy from Genesis Energy.

- Liquid hedge market

3. All major generators (with over 500 MW of capacity) to put in place by 1 June 2010 an electricity hedge market with the following characteristics:
   - standardised, tradable contracts
   - a clearing house to act as a counter-party for all trades
   - low barriers to participation and low transaction costs
   - market makers (offering buy and sell prices with a maximum spread) to provide liquidity.
4. An assessment to be made by 1 June 2011 of satisfactory market liquidity, defined as 3,000 GWh of ‘unmatched open interest’ (contracts without matching offsetting contracts).

To improve wholesale and retail competition and help restrain prices

Recommendation 18

Introduce, as a priority, a transmission hedging mechanism to assist retailers manage risks created by transmission congestion.

1. Reason for recommendation

- The risk of price spikes at offtake nodes caused by transmission congestion is a significant disincentive for retailers without generation assets in that region. Transmission hedges help manage that risk.

2. Submissions

- Most submitters agreed that transmission hedges are a priority and long over-due

- Views were split on whether LRAs or FTRs are better

- The EC said it is issuing a discussion paper in Q3 2009

- Some major users recommended abolishing nodal pricing and shifting to zonal prices.

3. Comment

- This issue requires priority attention. The EC now seems to be focused on making and implementing a decision.

- Note: there is a continuing risk of paralysis in decision-making. The issues are very complex and contentious, with big winners and losers, and trade-offs are required between (i) theoretical perfection and (ii) practicality and timeliness in getting benefits of increased competition.

4. Recommendation

Introduce, as a priority, a transmission hedging mechanism to assist retailers manage risks created by transmission congestion.

To improve wholesale and retail competition and help restrain prices

Recommendation 19

Facilitate greater demand-side participation in the wholesale market, including providing for:

19.1 More accurate forecasting of spot prices.
19.2 Real-time (not ex post) spot prices.
19.3 Demand response to be dispatched in the same way as generation.

1. Reason for recommendation

- Good demand-side response improves the overall efficiency of the market and has the potential to reduce market power. It is a neglected area in the market rules.

2. Submissions

- Widespread agreement this is an important area.

- Some scepticism about despatchable demand. However, Norske Skog was very enthusiastic (can offer 120MW).

- Some major users advocated further consideration of a day-ahead (ex ante) market (see Appendix 20 of the Review).

- EC said it is releasing a discussion paper in October 2009. This includes property rights on load management (eg ripple control).

3. Recommendation

Facilitate greater demand-side participation in the wholesale market, including providing for:

1 More accurate forecasting of spot prices.
2 Real-time (not ex post) spot prices.
3 Demand response to be dispatched in the same way as generation.

To improve wholesale and retail competition and help restrain prices

Recommendation 20

Allow lines companies to provide electricity retailing services in their local areas subject to:

20.1 Retaining the existing provisions in the Electricity Industry Reform Act that:

- Require corporate separation and compliance with arms-length rules between lines and energy (generation and retailing) businesses.

- Require lines companies to put in place transparent and non-discriminatory use-of-system agreements with their retail business.

- Have the effect of prohibiting common ownership between lines businesses and generators owning more than 100MW of generation connected to the national grid.

20.2 Prohibiting a retail business owned by a lines business from buying the customer base of an existing retailer (to ensure there is a net increase in retail competition).

1. Reason for recommendation

- To allow for more retail competition, particularly in smaller and remoter areas, while managing risks of anti-competitive behaviour and large-scale vertical integration between generator-retailers and lines businesses.

2. Submissions

- Strongly divergent views

- <u>Some strong opposition to allowing lines into retailing</u> (MRP, Todd, Business NZ sceptical)
  - o Any natural monopoly allowed to compete in upstream or downstream markets will have the incentive and ability to lessen competition. The outcome will be regional monopolies rather than vigorous competition.
  - o Todd: trusts will buy goodwill for their retailer (eg with rebates); lines businesses have access to valuable information (metering data, premium customers, network capability)

- <u>Some generally supported (or accepted) the recommendations, provided that all or most of the restrictions in the recommendations remained</u>
  - o MEUG, Contact, Meridian, Federated Farmers

- <u>Lines businesses strongly supported allowing lines into retailing, but strongly opposed the remaining restrictions.</u>

- Oppose: corporate separation; restrictions on buying customer bases[16]; and retaining ownership separation between >100MW grid-connected generation and lines
  - Argue these restrictions are unnecessary[17], inefficient/bureaucratic, and will discourage entry (especially given unavailability of hedges except from competitor generator-retailers), thereby limiting the extent of competition with incumbent retailers.

- Specific suggestions in various submissions:
  - Prevent trusts making distributions (rebates etc) only to customers of trust-owned retailer
  - Allow lines to buy customer bases when retailer is distressed (and would exit market anyway): provide powers for the CC to give exemptions
  - Remove current 50MW cap on thermal generation.

- Many submissions emphasised the importance of a liquid hedge market (whether through mandatory hedge offerings or a separation of generation and retail) as a necessary condition for retail entry by lines businesses. (See recommendation 17).

3. Comment

- Keep recommendation, but:
  - Prohibit trusts making distributions (eg rebates) which discriminate in favour of the customers of the trust-owned retailer
  - Remove current 50MW cap on thermal generation

- Note importance of:
  - Providing for a liquid hedge market: see recommendation 17
  - Moving to more standardised line tariff structures/terminology and business rules: see recommendation 21. (Risk that allowing lines into retailing encourages smaller lines companies to keep complex tariff structures and rules).

4. Recommendation

- Allow lines companies to provide electricity retailing services in their local areas subject to:

  1. Retaining the existing provisions in the Electricity Industry Reform Act that:

     - Require corporate separation and compliance with arms-length rules between lines and energy (generation and retailing) businesses.

     - Require lines companies to put in place transparent and non-discriminatory use-of-system agreements with their retail and generation business.

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[16] Lines businesses argued that it would be difficult to enter the retail market unless they could obtain economies of scale (given fixed costs of call centres etc).

[17] Lines argued that ownership separation of lines and energy was no longer required because the scope for cross-subsidising competitive activities had been removed by price control of lines businesses under the Commerce Act.

- Have the effect of prohibiting common ownership between lines businesses and generators owning more than 100MW of generation connected to the national grid.

2. Prohibiting a retail business owned by a lines business from buying the customer base of an existing retailer (to ensure there is a net increase in retail competition).

3. Prohibiting trust-owned lines companies making distributions which discriminate in favour of the customers of any particular retail business

- Remove the 50MW cap in EIRA on lines building thermal generation.

To improve wholesale and retail competition and help restrain prices

Recommendation 21

Develop more standardised tariff structures and business rules for use-of-system agreements for lines businesses to facilitate access by retailers.

1. Reason for recommendation

- To reduce the complexity and cost for retailers of dealing with a multiplicity of tariffs and business rules, which discourages new entrant retailers.

2. Submissions

- Strongly divergent views (lines companies versus everyone else)

- Many submitters (except for lines businesses) supported the recommendation, and wanted the current model code made mandatory.
    - o Retailers generally considered this the single biggest barrier to competition. Meridian said it had to deal with over 2000 separate tariffs[18]. This significantly increased the cost of doing business and call centres.

- Lines companies strongly opposed
    - o Do not consider there is a problem, or see it as a 'second-order' issue
    - o Argue that mandatory provisions would reduce flexibility and innovation, and not allow tariffs to take account of different circumstances (age of network, geography, types of customers etc)
    - o Any requirements should be at the level of pricing principles only
    - o Critical of the fact that both the EC and the CC are involved in distribution pricing methodologies. Most wanted it to be exclusively the CC's jurisdiction[19].
    - o Some noted that getting rid of low fixed charges would reduce tariff complexity.

- EC agrees that this issue is important for competition and market efficiency. It is currently consulting on a discussion paper and is convening discussions between market participants. Several said they supported the EC's current work.

3. Comment

- Keep recommendation.[20]

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[18] PowerNet, with 30,000 customers, has 46 tariff categories. MRP notes there is much more competition in small networks with simple tariffs (eg Waipa) compared to those with complex tariffs (eg Horizon, Alpine, Lines Company).

[19] Some non-lines submitters, eg Genesis and MRP, agreed. See recommendation 27.

[20] Note that Ofgem has recently decided it needs to impose a unified distribution pricing methodology on distribution companies on two main grounds, one of which was that "*the range of different methodologies in use across the country imposes significant costs and acts as a barrier to entry to generators and suppliers [i.e. retailers]*". (The other reason was to deliver superior pricing signals to deliver more efficient local generation and demand-side response as alternatives to network investment.) It should be noted that there are only 14 distribution areas in Britain, with an average number of 1,800,000 ICPs per area, compared with the ≈ 28 network charging areas in New Zealand with an average number of 50,000 ICPs per area.

- Remove the overlap in regulator jurisdiction on distribution pricing methodologies. This should be solely the EC's responsibility, because of its importance to competition in the electricity market, demand-side management, contracts with consumers and the like. (That is, the CC should determine the overall revenue requirements of lines businesses, including to cover the cost of new investments, while the EC should have responsibility for policy on tariff categories and structures ie how and from whom the total revenue requirements are recovered).

4. Recommendation

Develop more standardised tariff structures and business rules for use-of-system agreements for lines businesses to facilitate access by retailers.

Amend s54 of Part 4 of the Commerce Act (on input methodologies) to clarify that the Commerce Commission should not develop pricing methodologies where a sector-specific regulatory body (such as the Electricity Commission) advises that is has done so or is proposing to do so.

To improve wholesale and retail competition and help restrain prices

Recommendation 22

Ensure that guidelines and standards on smart meters provide for (or allow upgrades for) energy efficiency capability, open access communications, customer switching, and the development of smart networks.

1. Reason for recommendation

- Smart meters are expected to play an increasingly important role in demand-side management by consumers and in the development of smart networks. Various parties are rolling out different models and technologies, and current projections are that around 1.3m homes will have smart meters installed by 2012.

2. Submissions

- Many submitters supported guidelines but opposed mandatory technology standards, except (as required) to (i) prevent barriers to customer switching and (ii) allow for data sharing
  - This is area of rapidly developing technology; there is a risk of locking-in obsolete technologies[21] and/or creating new monopolies/oligopolies; international agreement on protocols is still being developed.

- Many lines companies argued that lines should have overriding responsibility for meters and management of data bases, particularly because of the importance of smart networks[22]

- Many submitters agreed with the PCE that the specifications of meters currently being installed benefited retailers, not consumers, and urged mandatory minimum standards and requirements. Many also emphasised the value and importance of ripple control (of hot water heating), and urged that it be retained.

- PCE recommended that either (i) HAN (home area network) capability and standards should be mandatory (using the protocol adopted in Victoria) or (ii) roll-out of meters should be stopped until issues relating to HAN capability are resolved. Note: the Commerce Committee is considering the PCE's study.

- EC has recently released a paper on metering, including on data management. It is required by the GPS to report to the Minister by the end of 2009 on whether mandatory metering standards should be introduced.

3. Comment

- This is an important but complex area, with rapidly developing technologies, and a multiplicity of parties with differing interests (retailers, lines companies, Transpower, and the individual consumer).

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[21] Eg, issue of whether meters should have sophisticated load management capabilities, or whether they should just be remote reading devices with management done by PC/internet.

[22] Local networks and the grid want access to smart meter information and to be able to remote control load to assist with better outage detection and quality monitoring, to facilitate active line management to reduce energy losses, and to help defer the need to for new investments to handle peak loads.

- A key issue is who controls load management functions: the consumer, the retailer, or the distributor? This might best be considered as a contractual matter: the consumer should have control: if the retailer wants to be able to exercise control it should seek the consumer's agreement through special tariff offerings: if the distributor wants to be able to exercise control and/or obtain access to data, it should make special (distribution) tariff offerings to retailers.

- No change to recommendation.

4. Recommendation

Ensure that guidelines and standards on smart meters provide for (or allow upgrades for) energy efficiency capability, open access communications, customer switching, and the development of smart networks.

To improve wholesale and retail competition and help restrain prices

Recommendation 23

Encourage retailers to make tariffs available, as an option for consumers, that provide incentives to better manage electricity consumption including through shifting load to off-peak times and conservation during dry years.

1. Reason for recommendation

- To allow for more and better demand-side responsiveness

2. Submissions

- General support, though differing views on whether this should be a mandatory or voluntary requirement
  - Major users favoured making mandatory (to allow for better consumer response to high spot prices)
  - Retailers generally considered that tariff options should be left to market forces (which, they say, provide incentives for tariff innovation).

3. Comment

- Retain

4. Recommendation

Encourage retailers to make tariffs available, as an option for consumers, that provide incentives to better manage electricity consumption including through shifting load to off-peak times and conservation during dry years.

To improve wholesale and retail competition and help restrain prices

Recommendation 24

Ensure that all wholesale market data is publicly released the following day to improve scrutiny of and by market participants.

1. Reason for recommendation

- To improve transparency and help disincentivise the exercise of market power.

2. Submissions

- General support
- Some submitters (MEUG, Genesis) said it was important that the EC (or an independent body) undertook 'market surveillance' analysis of disclosed information, particularly where there were concerns about the possible exercise of market power. (This information would feed in to whether rule changes were required).
- Some submitters noted that it was important that the information be provided free of charge (with costs recovered by levy), to facilitate scrutiny and analysis by multiple parties.

3. Comment

- Retain, but add recommendations about (i) the need for market monitoring and investigations, and (ii) the released information should be available free-of-charge.

4. Recommendation

- Ensure that all wholesale market data is publicly released the following day, with no or minimal cost, to improve scrutiny of market participants.
- Ensure that the EMA provides for on-going monitoring and analysis of data, and undertakes investigations if required on matters of serious concern.

To improve wholesale and retail competition and help restrain prices

Recommendation 25.2

Encourage and facilitate customer switching through:

25.1 Providing $5 million a year, from electricity levy funding, to promote the benefits of customer switching. The fund should be contestable, and should continue for as long as demonstrated benefits, in terms of savings to consumers, exceed $10 million a year.

25.2 Shortening the timeframe for switching between retailers from 23 days to three days for customers with smart meters.

25.3 Improving the Powerswitch website by requiring retailers to provide updated information to improve its accuracy and coverage.

1. Reason for recommendation

- To encourage more customer switching, to improve the level of retail competition.

2. Submissions

- <u>Mixed views on the $5m fund</u>
  - o Most submitters supported on the grounds that this would facilitate more vigorous retail competition
  - o Some submitters opposed, on the grounds that promotion of switching should be left to retailers and market forces, or on the grounds that prospects for competition and hence the potential benefits from the fund were limited. Major users wanted to be sure they would not be levied to cover the cost
  - o Some submitters (consumer/community groups) recommended that the fund be targeted to ensure equality of access for low income and vulnerable consumers
  - o A number recommended the fund have a limited life, say 2-3 years.

- <u>General support for tighter switching timeframe</u>
  - o But retailers generally considered 3 days was too tight (for example, because of the 7 day cooling off period under the Door to Door Sales Act, or the need for meter readings and data reconciliation)
  - o Some retailers considered it was best to have a tighter timeframe for all meters, not just smart meters
  - o Trustpower suggested 75% in 3 days and 100% in 10 days for all meter types. Genesis suggested 100% in 10 days.

- <u>General support for improving the Powerswitch website</u>
  - o Some noted that it would be difficult for Powerswitch to compare more sophisticated tariffs (eg time of use)
  - o Consumer NZ, which operates Powerswitch, advocated preventing retailers changing tariffs more than twice yearly.

3. Comment

- Retain recommendations, but:
  - o Generalise the recommendation on timeframes for customer switching
  - o Provide for a three year life on the $5m/yr fund

- Note that EC is currently consulting on the consumer switching timeframes and requirements.

4. Proposed recommendation

Recommendation 25.2

Encourage and facilitate customer switching through:

1. Providing a contestable fund of $5 million a year for three years, from electricity levy funding on retailers, to promote the benefits of customer switching

2. Shortening the maximum time allowed for retailers to complete customer switching requests for all types of meter

3. Improving the Powerswitch website by requiring retailers to provide updated information to improve its accuracy and coverage.

To improve governance of the electricity sector

Recommendation 26

Replace the Electricity Commission with an Electricity Market Authority (EMA) as follows:

26.1 The EMA would be an Independent Crown Entity under the Crown Entities Act 2004.

1. Reason for recommendation

- To improve the independence of the electricity regulator, to avoid perception about risk political interference, and reduce the incentives for lobbying

2. Submissions

- <u>General support for setting up the EMA as an ICE</u>
  - o But MAF (not public) expressed concern that the government would have no powers short of new legislation to get outcomes it wanted (eg 90% renewable energy generation)
  - o Note: Business NZ queried whether there was a need for a sector-specific regulator at all (it said market participants should make the rules subject to general competition law)

- <u>General support for the EMA having the power to make rules without requiring Ministerial approval</u>
  - o But several advocated that the EMA should develop a protocol on its consultation procedures for consulting on and developing rules

- <u>Several submitters opposed retention of Government Policy Statements</u>
  - o Should be used sparingly, and should not be detailed and prescriptive

- <u>Some submitters advocated merits review of EMA rule-making</u>
  - o Particularly given independence of EMA, and (hence) lack of checks and balances on rules.

3. Comment

- Keep recommendation. (Note: Cabinet decisions required on rule-making powers.)

4. Proposed recommendation

Replace the Electricity Commission with an Electricity Market Authority (EMA) as follows:

- The EMA would be an Independent Crown Entity under the Crown Entities Act 2004.

To improve governance of the electricity sector

Recommendation 26.2

Replace the Electricity Commission with an Electricity Market Authority (EMA) as follows:

26.2 The EMA's objective would be to ensure the efficiency of the electricity market, including reliability, for the long-term benefit of consumers.

1. Reason for recommendation

- To narrow objectives

2. Submissions

- General support
  - Some major users recommended addition of 'secure'
  - MRP recommended addition of 'promoting competition'

3. Comment

- Agree with addition of 'secure' and 'competition'

4. Proposed recommendation

Replace the Electricity Commission with an Electricity Market Authority (EMA) as follows:

- The EMA's objective should be to promote secure and efficient operation of, and competition in, the electricity market for the long-term benefit of consumers.

To improve governance of the electricity sector

Recommendation 26.3 & 26.4

Replace the Electricity Commission with an Electricity Market Authority (EMA) as follows:

26.3 Board members would be appointed by the Governor-General on the recommendation of the Minister of Energy and Resources, and nominated as follows:

- Two members nominated by Consumer New Zealand and Business New Zealand respectively.
- One member nominated by generators and retailers.
- One member nominated by lines businesses including Transpower.
- One member and an independent chair nominated by the Minister.

26.4 The Minister would only be able to recommend appointments of persons nominated by market participants (as applicable), but would not be required to accept any particular nomination. Criteria for members would be set down in legislation (such as independence, expertise, and ability to work as a Board member).

1. Reason for recommendation

- To improve involvement of and accountability to stakeholders

2. Submissions

- Some submissions (eg Business NZ, Vector, Contact, MRP) strongly support stakeholder appointments
  - o But nearly all wanted changes to the balance of representation: eg lines wanted separate representation for lines and transmission; generator-retailers wanted two representatives; major users wanted a major user representative; consumer/user groups wanted a majority of consumers
  - o Some advocates dropping the requirement that (all) nominees be independent
  - o Business NZ not want Minister involved at all
  - o Some wanted the Minister to give reasons for rejecting a nominee

- Many other submissions concerned about the proposal for stakeholder nominees for a range of reasons:
  - o Several concerned about the practicalities of voting
  - o Concern that stakeholder representatives would be advocates for their nominating body
  - o Preferred that Minister invite stakeholders to recommend suitable persons for consideration.

3. Comment

- Drop formal stakeholder nomination processes and rights. Require Minister to invite nominations and to ensure that the Board has an appropriate range of skills and expertise.

4. Recommendation

Replace the Electricity Commission with an Electricity Market Authority (EMA) as follows:

- Board members should be appointed by the Governor-General on the recommendation of the Minister of Energy and Resources

- The Minister should be required to invite nominations from stakeholders for Board members (but would not be restricted to recommend only persons who have been nominated)

- Criteria for members should be set down in legislation (such as independence, expertise, and ability to work as a Board member).

To improve governance of the electricity sector

Recommendation 26.5

Replace the Electricity Commission with an Electricity Market Authority (EMA) as follows:

26.5 The functions of the EMA would be:

- Developing and approving market rules (including guidelines and model contracts).
- Monitoring compliance with rules and, through a Rulings Panel, penalising breaches.

1. Reason for recommendation

- Narrow the functions of the electricity regulator (to improve the quality and timeliness of its rule-making).

2. Submissions

- General agreement.
  - o Some submitters recommended adding market monitoring and analysis (see recommendation 24)

3. Comment

- Add market monitoring and analysis.

4. Recommendation

Replace the Electricity Commission with an Electricity Market Authority (EMA) as follows:

- The functions of the EMA should be:
  - o Developing and approving market rules (including guidelines and model contracts)
  - o Monitoring compliance with rules and, through a Rulings Panel, penalising breaches
  - o Monitoring and analysing market performance.

To improve governance of the electricity sector

Recommendation 26.6

Replace the Electricity Commission with an Electricity Market Authority (EMA) as follows:

26.6 The EMA would be required to set up working groups to prepare proposed rules, and the board would be required to hear representations on proposed rules from the chair of working groups before making decisions.

1. Reason for recommendation

- To improve stakeholder participation in rule-making.

2. Submissions

- Wide agreement:
  - Several submitters advocated that the EMA should develop a protocol on its processes for involving working groups
  - Some differences of views on how prescriptive the legislation should be on working groups. (EC said legislation should not be prescriptive)

3. Preliminary MED views

- Add requirement that the EMA should develop (and consult on) a protocol for working with working groups

4. Proposed recommendation

Replace the Electricity Commission with an Electricity Market Authority (EMA) as follows:

- The EMA should be required to set up working groups to prepare proposed rules, and the board should be required to hear views on proposed rules from representatives of working groups before making decisions

- The EMA should be required to develop, in consultation with interested parties, a protocol on its processes and procedures regarding working groups.

To improve governance of the electricity sector

Recommendation 27

Transfer approval of major grid upgrades to the Commerce Commission as part of its overall regulation of Transpower under Part 4 of the Commerce Act, but with reliability and service standards, transmission pricing methodologies, and the Grid Investment Test set by the EMA.

1. Reason for recommendation

- To reduce overlap between regulatory bodies and ensure that grid upgrades are considered as part of the overall regulation of Transpower's expenditure and revenues.

2. Submissions

- General agreement (apart from EC, and, in a revised submission, MEUG) on transferring responsibility for evaluating and approving grid upgrades to the CC

- EC said that:
  - o This would require duplication by the EC and the CC of engineering and economic expertise (CC needs such expertise for considering upgrades; EC needs for rule development and monitoring)
  - o There is no currently no duplication and overlap between the CC and the EC. There are two different jobs: evaluating specific projects (EC) and determining overall revenues and rates of return (CC).

- Most submissions also supported transferring responsibility for setting the GIT to the CC
  - o They considered this more efficient. They also saw risks in the EC retaining responsibility for setting the GIT (eg likely continue requiring shadow grid planning)
  - o But, Transpower and Vector supported the GIT staying with the EC (to provide for separation of rule-making and implementation)

- Some submissions considered that other parts of Part F[23] should also be transferred to the CC
  - o Some submitters said all or nearly all sections of Part F should be dealt with by the CC
  - o Other submitters considered that only the transmission pricing methodology should be transferred[24]

- General concern about risk of delays to current transmission upgrade proposals during the transition period.

3. Comment

[23] The main sections of Part F of the Electricity Governance Rules are transmission agreements (II); grid upgrades and investment (III); transmission pricing methodology (III); financial transmission rights (IV); service measures (V); outage protocols (VII).

[24] MRP noted that there were strong synergies between the reliability provisions of Part F and other parts of the rule-book (such as Part C on common quality and security).

- Retain recommendation, but transfer responsibility for determining the tests for grid upgrades to the CC, using the criteria in Part 4 of the Commerce Act. This will ensure that an appropriate test is developed encompassing all of Transpower's expenditure.

4. Proposed recommendation

Transfer approval of major grid upgrades, and determining the test for approving upgrades, to the Commerce Commission as part of its overall regulation of Transpower under Part 4 of the Commerce Act. (The remainder of Part F should remain with the EMA).

Transitional arrangements:

- EC will continue to process grid upgrade proposals under the GIT until the new legislation comes into effect and the EMA is established (indicatively 1 October 2010)

- Any incomplete evaluations of grid upgrade proposals at that time should continue to be considered by the EMA under the GIT until the earlier of (i) gazettal by the CC of an input methodology under Part 4 for making determinations on grid upgrade projects or (ii) 1 October 2011.

To improve governance of the electricity sector

Recommendation 28

Transfer the following functions to the System Operator:

28.1 Information and forecasting on security of supply. Long term forecasting, and preparation of the 'Statement of Opportunities' would be undertaken by MED alongside its preparation of the Energy Outlook.

28.2 Emergency management.

28.3 Operation of reserve energy (if retained).

1. Reason for recommendation

- To narrow the focus of the EMA (to improve the quality and timeliness of its rule-making); to take advantage of synergies available in System Operator (SO) functions; and to make the Statement of Opportunities (SOO) less prescriptive.

2. Submissions

- General agreement (apart from the EC re information and forecasting).

- EC said that transferring information and forecasting, and preparation of the SOO, would result in duplication of engineering, economic and forecasting resources and expertise, because the EC needs to retain such expertise in any event to undertake rule development and monitoring.
  - o It also suggested that preparation of the SOO by MED would be vulnerable to political interference and direction.

3. Comment

- No change to recommendation.

4. Recommendation

Transfer the following functions to the System Operator:

- Information and forecasting on security of supply. Long term forecasting, and preparation of the 'Statement of Opportunities' would be undertaken by MED alongside its preparation of the Energy Outlook.

- Emergency management.

To improve governance of the electricity sector

Recommendation 28.4

Transfer the following functions to the System Operator:

28.4 Contracting for market operations (for example, market clearance and reconciliation) pursuant to rules set by the EMA.

1. Reason for recommendation

- To help narrow the focus of the EMA (to improve the quality and timeliness of its rule-making).

2. Submissions

- Quite a bit of scepticism and concern expressed about this proposal
  - o Concern that Transpower would have conflicts of interest and that it had no special advantages as a contractor for market operations
  - o Concern that EMA may lose the benefits of detailed expertise as an input into rule-making
  - o Several parties suggested that if this proposal proceeded, further consideration should be given to setting up an Independent System Operator.

  - o Note: Transpower supported proposal, the EC opposed.

3. Comment

- Drop this proposal. Too many disadvantages:
  - o Adds too much complexity: four parties would be involved in market operations (EMA, Transpower/SO, CC and market operators) cf two at present (EMA and market operators)
  - o Lose detailed oversight by the EC of the SO's and market participants' costs
  - o Lose benefits of EMA knowledge of market operations for rule making.

4. Recommendation

Add to EMA functions (see recommendation 26.5): contracting for market operations (for example, market clearance and reconciliation).

To improve governance of the electricity sector

Recommendation 29

Require the EMA to set up and service a Security and Reliability Council, comprising senior level persons from the electricity market, to meet periodically to help monitor and provide advice on the System Operator's performance of its functions and on security of supply issues generally.

1. Reason for recommendation

- To provide senior level expertise to assist the EMA monitor the SO and provide advice on security of supply.

2. Submissions

- General support for setting up a SRC, but
  - Most submitters recommended that the SRC should be independent of the EMA
  - Some submitters (eg Contact) wanted it to play a much wider role (eg developing rules, providing input on transmission investments): others considered it was important that its role was kept narrow
  - Federated Farmers and consumers groups considered that there should be a majority of consumer representatives, and that consumer representatives should be resourced via levy.

3. Comment

- No change to recommendation. Not support making the SRC an independent body: too much risk that it ends up competing with the EMA rather than assisting it, and continually seeks more powers/roles/resources.

4. Recommendation

Require the EMA to set up and service a Security and Reliability Council, comprising senior level persons from the electricity market, to meet periodically to help monitor and provide advice on the System Operator's performance of its functions and on security of supply issues generally.

Indicative transitional arrangement and timetable

1. Cabinet decisions this year

2. Legislation

    - o Introduced by [February 2010]
    - o Passage Q3 2010
    - o Into effect 1 October 2010

3. Establishment of EMA

    - o Set up Establishment Board (serviced by MED and EC secondees) Q1 2010
    - o EGRs (rule-book) turned into a code incorporating changed institutional arrangements, by 1 October 2010

4. EC continues to operate meantime

    - o Including recommending amendments to the EGRs relating to its Market Development Programme.

Interface between recommendations of the Ministerial Review concerning market design and the Market Development Programme (MDP) of the EC

1. Many of the recommendations of the Review relating to market design are part of the EC's Market Development Programme. There is a high degree of agreement between these recommendations and the direction of the MDP.

2. Where there is a high degree of probability that the EC will develop satisfactory provisions as part of its MDP, no specific legislative provisions will be required.

3. However, where there is a risk that the EC may not develop satisfactory provisions, current intentions are that the new legislation should provide the Minister with the power[25] to make rules (code) in a limited number of specific areas in the event that the EMA does not develop satisfactory rules within a period prescribed by the Minister. Subject to the previous comment in 2, this may include issues such as:

    - o Compensation to consumers in the event of public conservation campaigns
    - o Scarcity pricing
    - o Demand-side participation in the wholesale market
    - o Transmission hedging arrangements
    - o Development of a more liquid hedge market.

4. Separate regulation-making powers[26] will be provided for consumer protection issues which are no longer part of the rule-making responsibility of the EMA, such as:

    - o Disconnection of vulnerable consumers
    - o Terms of contracts with consumers
    - o Low fixed charges.

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[25] This would be a discretionary power (ie 'may' not 'must').

[26] The Minister of Consumer Affairs will have powers to recommend regulations to the Governor-General. The Minster will be required to consult with the EMA and the Minister of Energy and Resources.

Appendix A

Issues raised in submissions regarding analysis of retail margins

Introduction

1. This paper comments on criticisms raised by Contact and Genesis regarding the Discussion Paper's analysis of wholesale prices, and thus the scale of retail margins[27].

2. The fundamental point of disagreement raised by Genesis and Contact is that the wholesale cost used in the analysis of residential customer margins was too low, thus giving rise to a perception of high residential retail margins. The specific points of disagreement are slightly different between the two companies as follows:

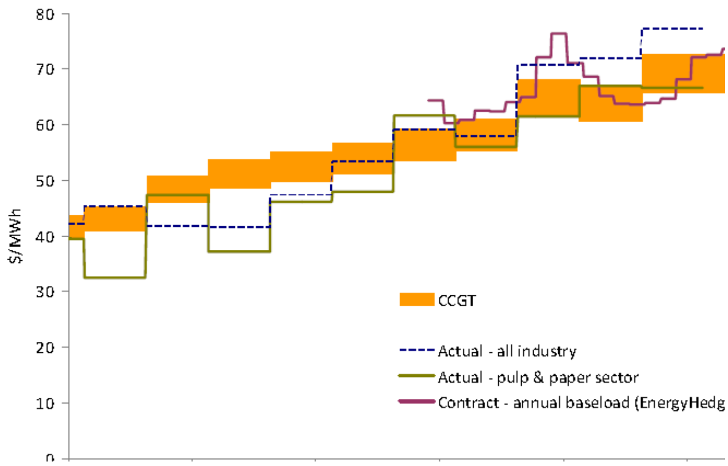
- Genesis: Estimation of the LRMC of a CCGT (combined cycle gas turbine) for 2008
- Contact: The extent to which prices in 2008 should reflect the LRMC of higher cost generation that will be needed in the future
- Contact & Genesis: The extent to which calculation of the wholesale component of residential tariffs should be different to that used for industrial customers.

3. This note discusses each of these points.

Estimation of new supply cost

4. Both Contact and Genesis agree with the Discussion Paper that, at least up until 2008, CCGTs should be considered as the appropriate type of plant to meet new demand growth, and thus that the LRMC of a CCGT should be an appropriate comparator for wholesale costs.

Figure 1: Contract price indicators and estimated costs of new supply

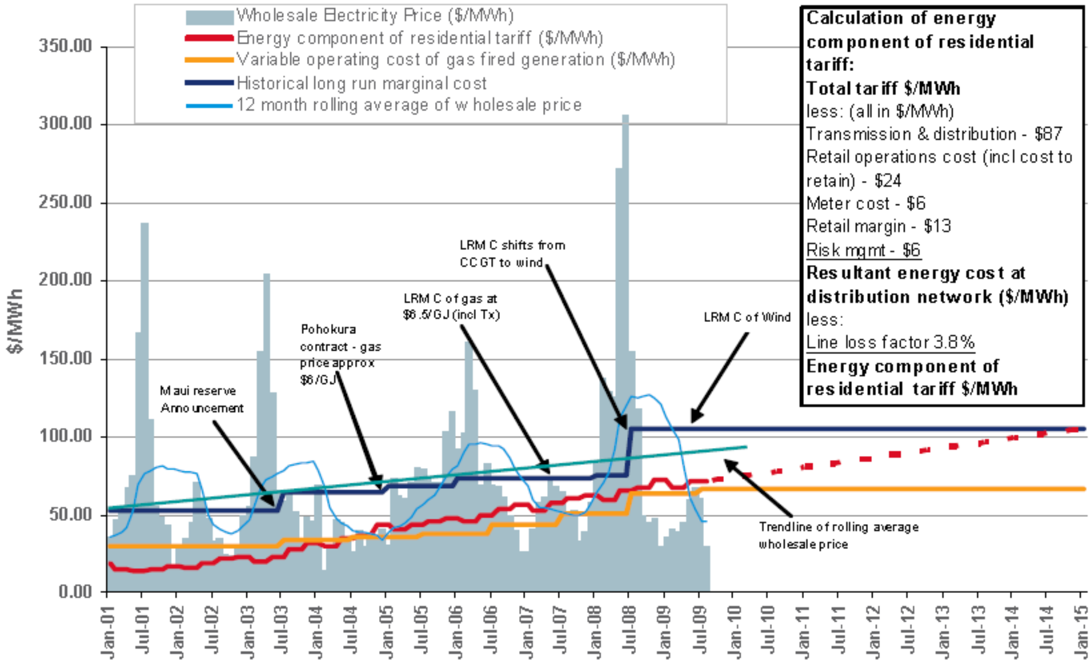


5. However there were differing views as to the cost of such generation:

- Figure 8 of the Discussion Paper (reproduced as Figure 1 on the right) presented a range for 2008 of between \$66 to \$73/MWh
- Contact presented a graph (reproduced as Figure 2 below) which appears to suggest that the cost of building a CCGT at the beginning of 2008 was \$73.5/MWh

[27] The other three main generators (Meridian, Mighty River Power, and TrustPower) were silent as to whether they agreed or disagreed with the analysis.

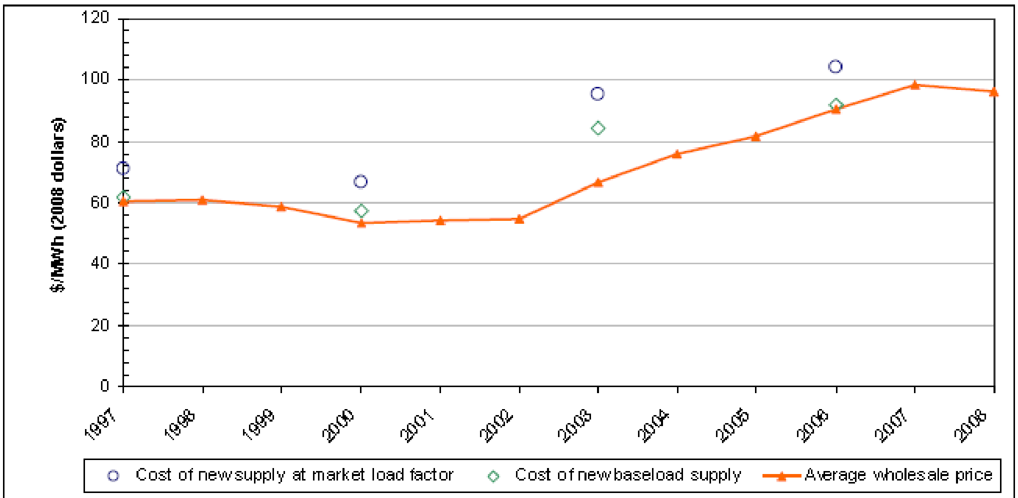
Figure 2: Contact Energy diagram "*Relationship between wholesale and retail prices*"



Source: Contact Energy August 2009 presentation on Contact's Annual Financial Results, and on page 10 of Contact's submission to the Ministerial Review

- Genesis suggests a cost of $90/MWh is the cost of building a CCGT "at present". They also present a table and figure (reproduced as Figure 3 below) which give the 2006 cost of building a CCGT. The table gives a price of $83/MWh, whereas the figure indicates a price of $92.5/MWh.

Figure 3: Genesis energy diagram "*Price path comparison with historical supply cost estimates*"



Source: Baseload generation costs for new supply from the MED Energy Outlook estimates for gas-fired CCGT. Genesis Energy calculations of allowances for losses and load factor – as explained in text.
Prices from MED data file tables on electricity end use (for March years)

Source: Figure 3 on p47 of Genesis Energy's submission to the Ministerial Review

6. A key difference between the Genesis data and the other figures is that the Genesis numbers include a cost of carbon. However, because a cost of carbon won't be introduced in New Zealand until mid-2010, it would not be appropriate to include such a cost in any analysis of prices in 2008.

7. Genesis doesn't state what cost of carbon was used to derive the $90/MWh figure, but refer to Figure 3 of page 27 of the Discussion Paper, where a cost of $NZ25/tCO2 was used. Such a price of carbon would add approximately $9.5/MWh to the cost of electricity from a CCGT.

8. To be comparable with the Contact and Discussion Paper figures, the Genesis figure of $90/MWh should be adjusted to *exclude* the estimated cost of CO2, and would become $80.5/MWh[28]. This cost estimate is still materially higher than the Discussion Paper numbers. However, the Discussion Paper estimate appears plausible given that:

- Contact (a privately owned company with strong commercial drivers) has cited CCGT costs that are broadly consistent with the Discussion Paper;
- If the Genesis cost estimates were correct, hedge contract prices have been well below the cost of building new CCGTs since 2003. Despite this, parties continued to build additional CCGT capacity (e3p was committed by Genesis), even though it presumably was expected to be loss making. This appears somewhat implausible.

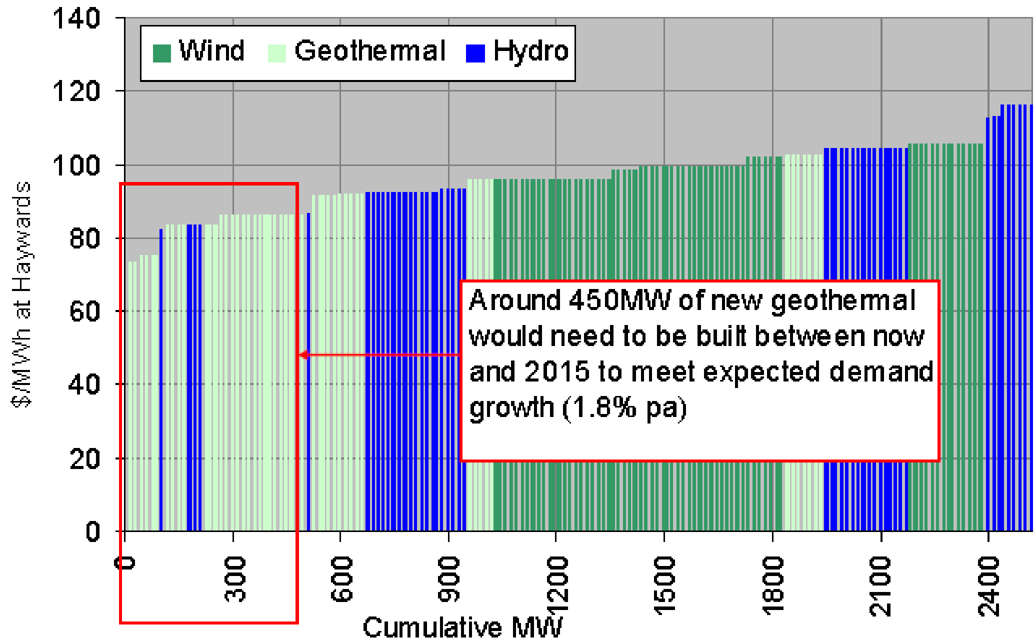
Extent to which prices should lead or lag cost of new supply

9. Looking forward, Contact agrees with the Discussion Paper's analysis that *it is unlikely that new coal or gas base-load plant will be built in the near future*"[29], and that prices will need to rise to the level of the new-build renewable plant required to meet demand.

[28] Incidentally, this $9.5/MWh cost of CO2 would explain the difference between the $83/MWh presented by Genesis in its table, and the $92.5/MWh presented in its figure.
[29] Genesis doesn't comment on what plant is likely to be built over the next decade.

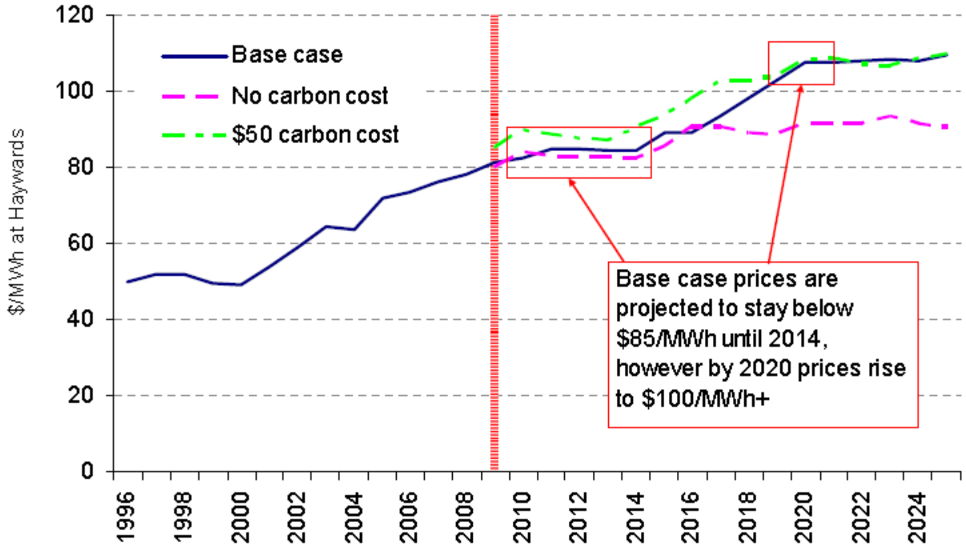
10. However, Contact disagrees with the analysis presented in the Discussion Paper (reproduced as Figure 4 and Figure 5 below) which suggests that the LRMC of new generation required to meet demand until 2015 will be in the $80 to $90/MWh range.

Figure 4: Projected LRMC of new base-load plant to 2025



Source: Figure 33 of Volume 2 of the Discussion Paper, originally sourced to MED

Figure 5: Projected wholesale electricity prices (average inflow year)

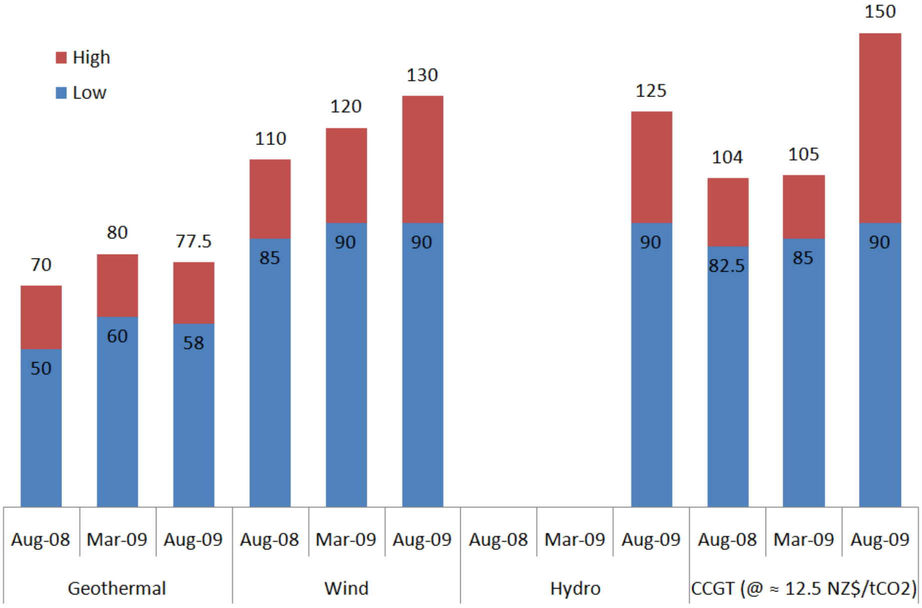


Source: Figure 32 of Volume 2 of the Discussion Paper, originally sourced to MED

11. Contact states that "*although there are some cost effective geothermal generation options that are likely to be supported by wholesale prices over the next few years, new wind and hydro generation will be more costly, perhaps significantly so. However, given the cost of other alternatives, and the availability of geothermal sources, wind and hydro will supply the bulk of New Zealand's new generation over the coming decade*".

12. Contact has made a number of public statements about its view of the likely costs for various types of new generation. The cost estimates from three of these presentations (given on Aug-08, Mar-09, and Aug-09 respectively) have been summarised in Figure 6 below.

Figure 6: Contact Energy estimates of new-entrant generation LRMCs

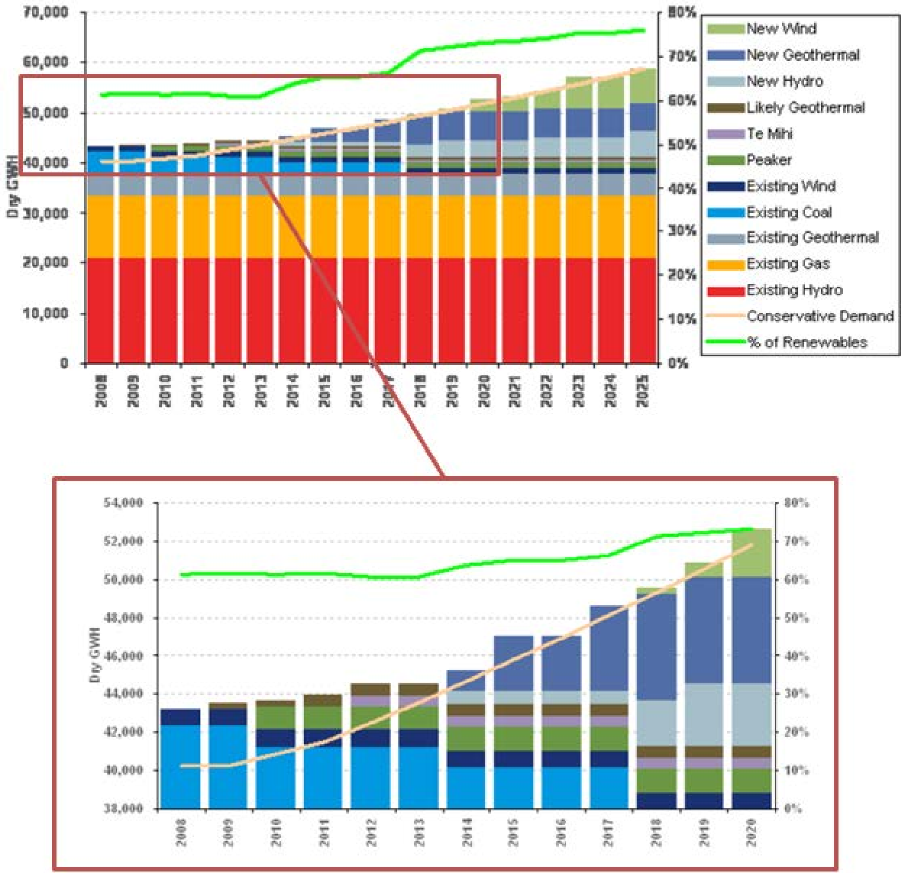


Source: Aug-08 and Aug-09 from Contact presentations on 2008 & 2009 annual financial results. Mar-09 from Contact investor presentation. Note: Low to High CCGT gas prices was $7/GJ to $10/GJ for Aug-08 & Mar-09, and $7.5/GJ to $15/GJ for Aug-09.

13. As regards the different technology types, these estimates appear to be broadly consistent with the Discussion Paper's estimates of LRMCs shown in Figure 4 above. Indeed, if anything Contact has a significantly *lower* view of the likely cost of geothermal than the MED.

14. Turning to Contact's statement that "*wind and hydro will supply the bulk of New Zealand's new generation over the coming decade*" this seems inconsistent with previous statements by Contact on this subject. Figure 7 below shows a chart presented by Contact to investors in March 2009.

Figure 7: Contact Energy diagram "*P90 Dry Supply and Demand Profile*"



Source: Contact Energy Mar'09 Investor Offsite presentation

15. The March 2009 presentation suggests that Contact doesn't expect *any* new wind to be built until 2018. Rather, the new build is almost entirely from geothermal projects (with the exceptions being Contact's 200MW peaker in 2010 and a single hydro-scheme in 2014). Given Contact's view on the cost of geothermal projects shown in Figure 6 above, this suggests prices in the \$70/MWh to \$80/MWh range, at least until 2018. This is consistent with the MED analysis presented in Figure 4 and Figure 5 above, but is not consistent with Contact's submission to the Ministerial Review. It is not clear why Contact's view has changed.

16. In addition, Contact's estimates of the cost of new generation shown in Figure 6 above indicate that its view of wind LRMCs are from \$90/MWh. Given that the best wind sites should be developed first, it is not clear why Contact's projection of long run marginal cost for wind starts at \$105/MWh.

17. Contact also suggests that "*prices will need to be approaching long run marginal cost (LRMC) in order that investment decisions can be made in advance of the generation being required. If those investment decisions are in respect of higher cost generation, developers will need to see a rising price path with some expectation that it will reach the cost of that new generation.*"

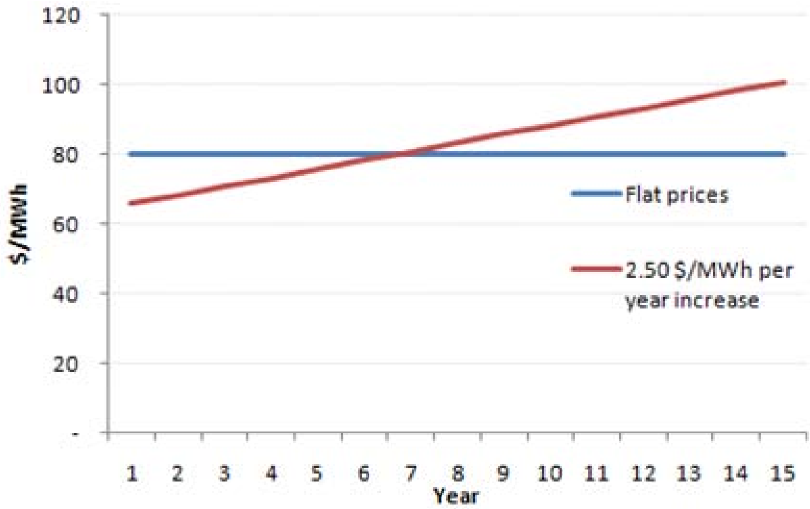
18. The key issue here is *when* contract prices need to reach the LRMC of the required new generation. Contact's analysis presented in Figure 2 above seems to indicate that in a market requiring future investment in higher cost generation, prices need to reach this level significantly in *advance* of the new generation actually being built.

19. However, such an outcome would result in generators earning significantly greater returns than actually required to make an investment economic. This is because if a developer has an expectation that prices are likely to rise in the future, they can

afford to build a new generation plant when prices are lower than their long-run marginal cost of generation, because sub-LRMC revenues in the early years would be offset by supra-LRMC revenues in later years.

20. For example, the MED projections of possible future prices shown in Figure 5 above suggest prices in 2010 of ≈ $80/MWh rising to ≈ $105/MWh in 2020. This indicates an average price increase of $2.5/MWh per year. If a generator with an LRMC of $80/MWh and a project discount rate of 7.5% had a reasonable expectation that prices were going to rise by $2.5/MWh per year, they could afford to build their plant seven years before prices reached $80/MWh, when prices were only $66/MWh. This is illustrated in the diagram below which shows two price paths which deliver exactly the same revenue NPV over a 15 year periods when measured with a 7.5% discount rate.

Figure 8: Illustration of the impact a rising wholesale price has on when it is profitable to build a new generator



Source: Illustrative data

21. MEUG, on page 3 of their submission to the Ministerial Review draws out this point further where they note that wholesale prices have risen substantially since e3p was commissioned in 2007. If you assume that wholesale prices in 2007 reflected the LRMC of e3p in that year, then *"within 2 years of building e3p, Genesis Energy are already earning well above LRMC."* They go on to state *"We don't think any capital intensive industry in a competitive market could expect to be earning economic rents in such a short time."*

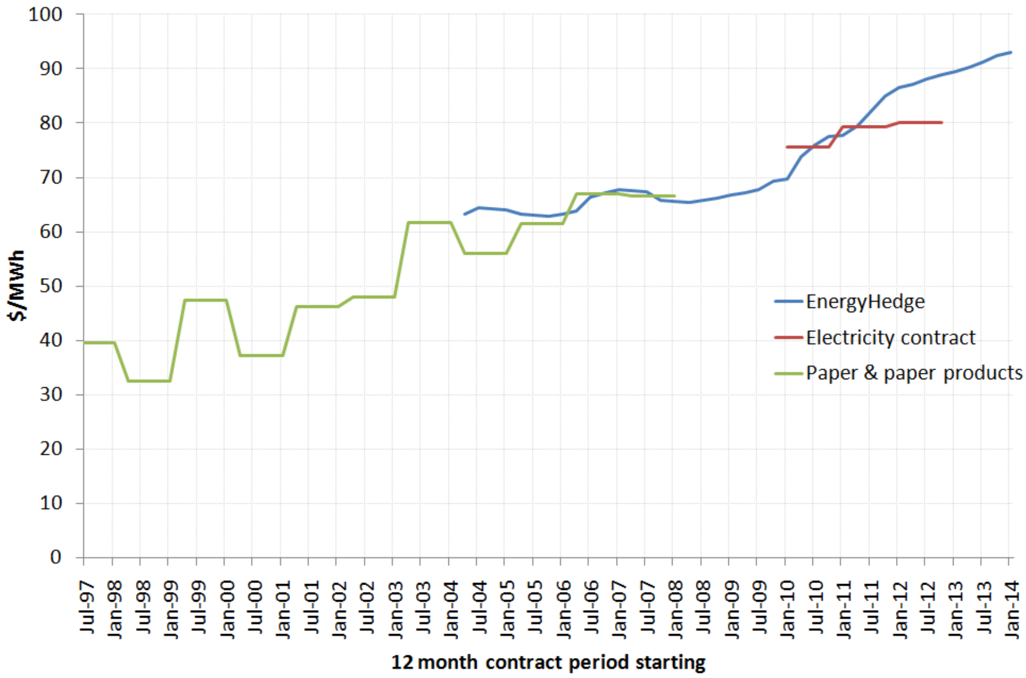
22. Another important conclusion from this analysis is that the appropriate metric to compare the wholesale component of residential retail tariffs is observed wholesale *contract* prices, not the LRMC of the marginal plant built in that year. This is consistent with similar analysis undertaken by overseas regulators. For example, in its analysis of UK residential margins, Ofgem uses observed hedge contract prices as the appropriate wholesale cost metric.

23. In summary:

- There does not appear to be anything to suggest that the MED analysis presented in the Discussion Paper is materially wrong with respect to future generation developments and their associated LRMCs.
- Nor is there a requirement that contract prices need to 'lead' the cost increases associated with developing higher cost generation. Rather, in a rising market some form of 'lagging' effect would be consistent with generators earning sufficient returns to make their investments economic.

24. These results are consistent with observed contract prices as shown in Figure 9 below, which indicate wholesale prices for calendar 2010 in the $70 to $75/MWh range, and for calendar 2011 in the $80/MWh range.

Figure 9: Comparison of various wholesale contract indicators[30]



Source: Based on data from the MED Energy Data File (for Paper & paper products), EnergyHedge, and www.electricitycontract.co.nz. Data source in September 2009.

25. Further, it should be noted there has been considerable softening of EnergyHedge prices for 2010 and beyond over the past few months. For example in May 2009, a 2012-CAL contract was trading at $95/MWh, whereas at the time of writing this note (September 2009) 2012-CAL is trading at $86.5/MWh.

End-use customer prices

26. There have been significant differences in electricity price movements (excluding network charges) across customer classes, as indicated in Figure 9 of the Discussion Paper (reproduced as Figure 10 below).

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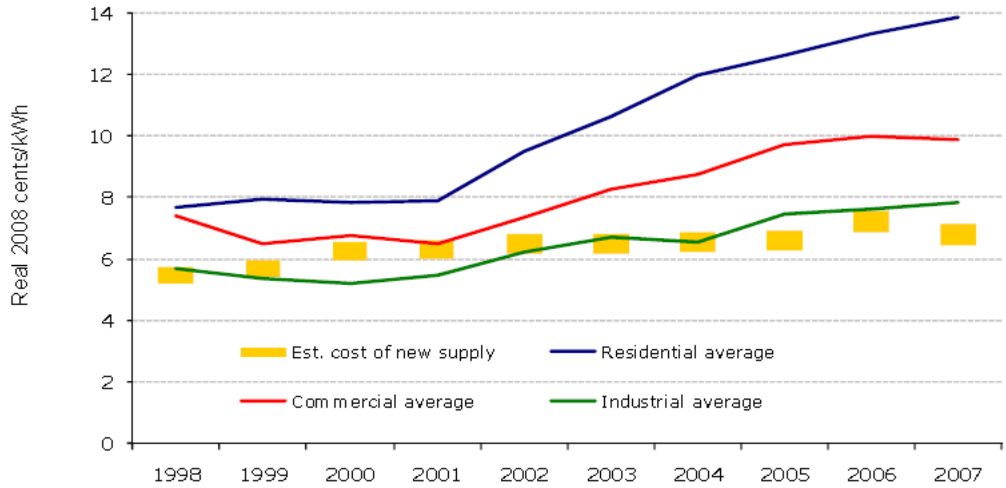
[30] The 'Electricity contract' data represents the most recent forward trades of any material.

Figure 10: Average cost excluding network charges



Source: Figure 9 of the Discussion Paper, originally sourced to MED Energy Data File, Statistics NZ, Electricity Commission

27. The Discussion Paper stated that "*the increase in energy costs for residential and commercial users appear to have significantly exceeded the movement in the cost of new supply*", and "*retail margins for residential users in particular appear to have increased substantially in recent years*".

28. Both Contact and Genesis present arguments which suggest that when the particular characteristics (and associated additional costs) of residential customers are taken into account, the retail margins are not excessive. Such factors include:

- The 'shape' of residential consumption and prices
- Location price risk
- Losses
- Retail cost-to-serve + metering
- Risk management

29. In other words, the sum of the above factors will 'bridge the gap' illustrated in Figure 10 above between the observed energy component of residential tariffs of ≈ \$138/MWh, and the observed baseload wholesale cost of ≈ \$67/MWh.

30. This section discusses the specifics of each of these points, as well as addressing Contact's suggestion that a number of these costs *"may not have been properly captured in the discussion document"*.

'Shape' of retail consumption and prices

31. Both residential consumption and wholesale prices exhibit significant 'shape', with consumption and prices being broadly correlated, typically with highest values in winter peak periods and lowest values during summer night periods.

32. The analysis for the Electricity Commission's Market Design Review took account of this fact by scaling the time-weighted average (i.e. baseload) wholesale contract price by observed historic demand-weighted average / time-weighted average (DWA / TWA) factors. The demand shape used to perform such demand-weighting scaling was actual market demand profiles (so-called 'Q-files') for a 2 year period until mid-2007, and the price shapes were based on historic prices for the period 2000 to 2006.

33. On average across the various regions, this led to a DWA / TWA scaling factor of 1.06. When applied to the $67/MWh baseload contract cost in given in paragraph 29, this leads to a price increase of ≈ $4.2/MWh.

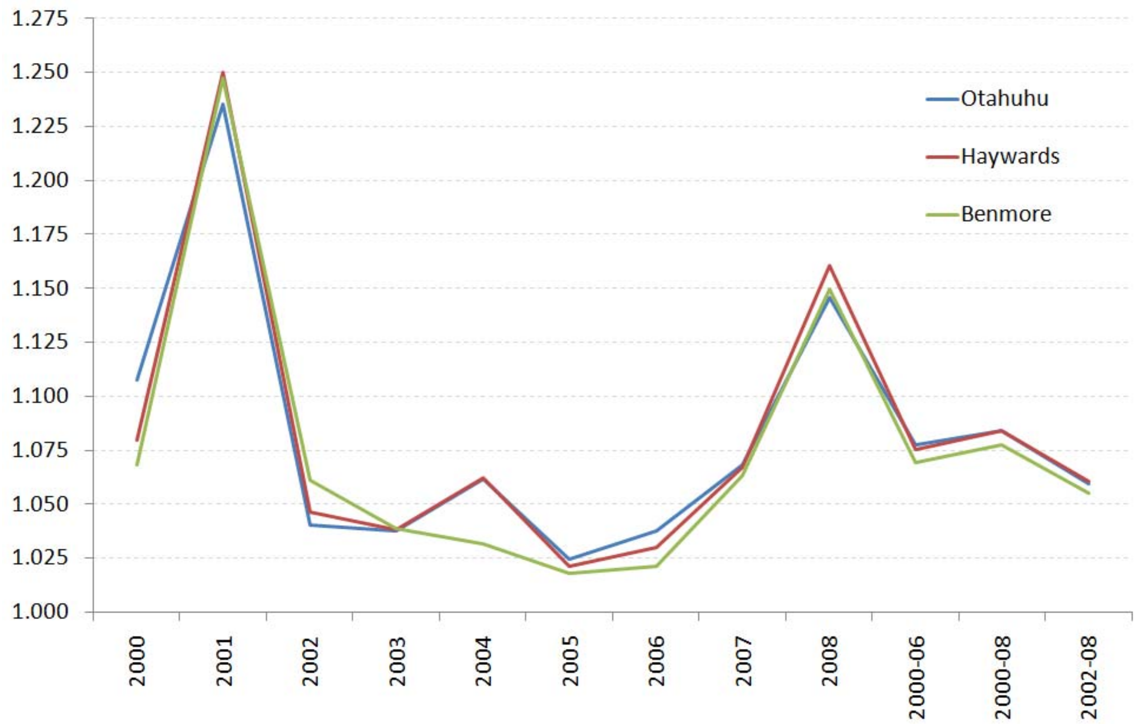
34. Genesis in its submission took a different approach. They suggested that the fixed cost component of a CCGT (namely $27/MWh[31]) should be factored by the average residential load factor of 60% to give a fixed cost component of $45/MWh. Thus, they said $18/MWh (being 45-27) should be added onto the baseload cost.

35. When applied to the $67/MWh baseload contract cost given in paragraph 29, this gives a DWA / TWA factor of 1.27. This is substantially greater than both the figure used in the Electricity Commission's margin analysis and, by extension, the premium observed in the market to date.

36. The difference between the two approaches may be due to the fact that to date, New Zealand has generally been energy constrained rather than capacity constrained, and as such some contribution to cover the cost of capacity has come from periods of energy scarcity. As New Zealand becomes progressively capacity constrained in the future, it should be expected that prices become peakier, and DWA / TWA factors should start to approach the levels indicated by the Genesis approach. However, it is likely that such a transition will occur over time.

37. Figure 11 gives an indication of how the average DWA / TWA factors would be impacted by inclusion of the 2008 dry year. While 2008 was an extreme year, its inclusion does not suggest that DWA / TWA factors of ≈ 1.06 to 1.08 would be wrong.

Figure 11: Demand-weighted average / Time-weighted average (DWA / TWA) factors for each of the years 2000 to 2008, and for averages of multiple years



Source: Historic half-hourly spot prices and 'Q-file' demand profiles for Wellington

[31] This seems reasonable, and compares with a figure of $25/MWh which can be inferred from the numbers presented by Contact Energy as illustrated in Figure 6.

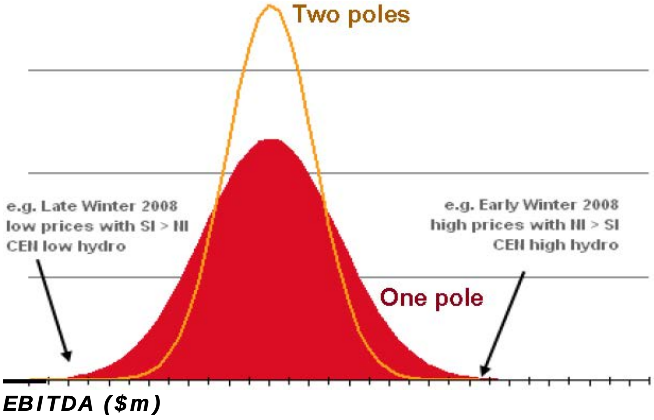
Location price risk

38. Contact has commented on the significant location risks it perceives in certain areas, especially Wellington and the South Island due to transmission constraints in dry years. In its March 2009 presentation to investors, it suggests that it has substantially increased its South Island risk management margins (and associated tariffs) to manage this risk. This is illustrated in the following slides from its presentation:

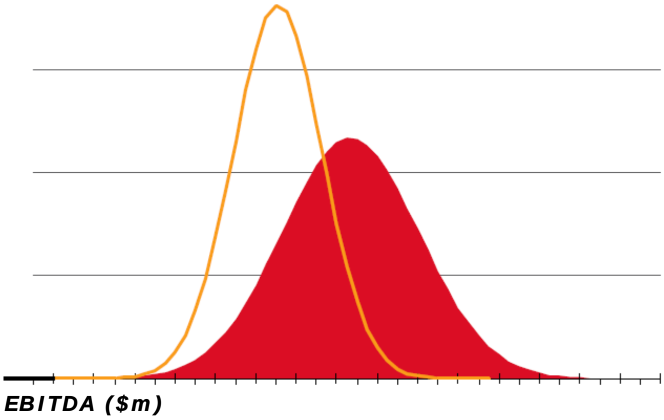
Figure 12: Illustration of Contact Energy's approach to South Island locational risk management. Note: Non-zero start of x-axis

Source: Contact Energy March 2009 investor presentation

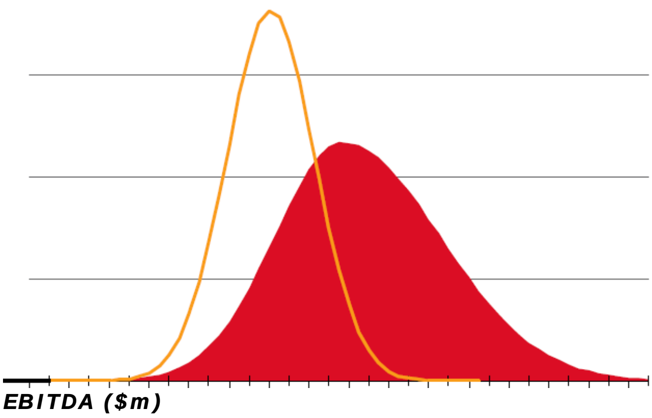
"The loss of pole 1 – unmitigated"



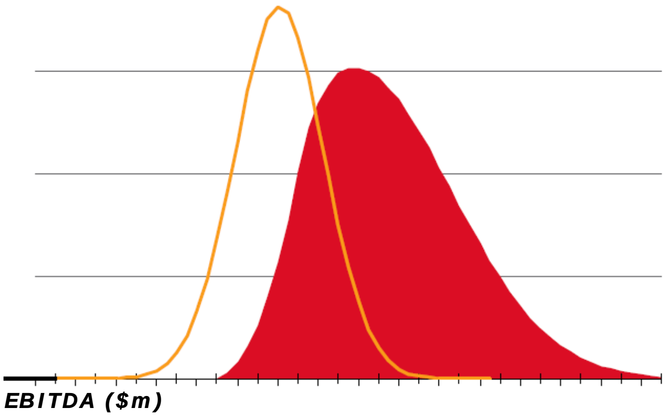
"South Island risk management margins have been adjusted to help mitigate the downside financial risk"



"Peakers and storage will provide upside potential"



"The return of the second pole will narrow the distribution but provide continued access to upside"



39. Contact's analysis indicates that its mean earnings outcome (EBITDA) has not changed with loss of Pole 1, but that the spread of possible outcomes has widened (upper left chart). To address this wider spread, Contact increased South Island and Wellington prices to increase its expected mean earnings (upper right chart). Although the charts don't include a scale, the price increase was around 10%, and expected earnings would be expected to increase by a larger figure (as expected costs don't change). This raises a question about the nature of the trade-off between risk and earnings, but this issue lies out of scope for this note.

40. That said, the issue of location price risk is material and needs to be factored in retail margin analysis. The Electricity Commission's Market Design Review sought to do so by adjusting a Haywards wholesale price by a location factor for each particular region – i.e. effectively adjusting the mean wholesale price outcome for each location. The location factors used were based on historic 2003 to 2006 location factors. To the extent that future location factors are likely to be materially different to historic location factors, such an approach will not properly reflect the location risk.

41. However, given that the issue in question is the relativity between residential customers and industrial customers, and given that there is a reasonable geographical spread of all types of customers, it appears unlikely that locational price risk would account for the differences across customer types.

Losses

42. Both Contact and Genesis apply an uplift to the wholesale cost to take account of line losses in transporting power to the customers' meter. Contact use a number of 3.8% (presumably reflecting transmission losses), and Genesis use a number of 10% (presumably reflecting transmission and distribution losses).

43. The Electricity Commission's Market Design Review approach was to take a common baseload wholesale contract figure (an EnergyHedge figure of $66/MWh) at Haywards, and scale it by the appropriate location factor for each region (which effectively takes into account transmission losses and average constraints), and then scale each tariff by the appropriate distribution losses for each region.

44. In short, the treatment of network losses would not account for the differences of view.

Retail cost-to-serve (CTS) + metering

45. The Electricity Commission's Market Design Review subtracted an average cost-to-serve of $170 per customer per year, and metering costs of $44/year. When spread across the average residential consumption of 7.63 MWh/yr[32], this equates to a cost of $22.3/MWh and $5.7/MWh, respectively.

46. Contact suggests that the CTS and metering numbers are $24/MWh and $6/MWh, respectively, which equate to annual figures of $183/yr and $46/yr when using the 7.63 MWh/yr consumption figure.

47. Genesis suggests "*an average retail operation cost of $100 per customer per year, or $10/MWh*". This cost-to-serve number seems very low compared with other estimates of NZ cost-to-serve, plus the implied average residential consumption is 10 MWh/yr which seems very high. Further, it is not clear how Genesis has treated metering costs. Overall, the Contact and Market Design Review figures are very close (especially allowing for the 12 month difference in the dates of preparation) and appear to be appropriate.

48. On this point, it is worth noting that Appendix 1 of the Electricity Commission Market Design Review presented analysis which indicated that a cost-to-serve of $170/yr was high by international standards (with levels of $100 to $120 more typically found overseas), and postulated that retail competition pressures may not provide sufficient incentive on NZ retailers to operate at best practice cost levels.

Risk management

49. Contact suggests an additional $6/MWh should be added to wholesale costs to account for risk management. As noted previously in paragraphs 38+, Contact perceives significant locational price risk in a number of areas.

50. However, it is not clear that residential customers would have systemically greater location risk than industrial customers. In any case, even if $6/MWh was added to wholesale costs for residential customers (in addition to uplift for location and price shape factors etc), it would not explain the difference between observed residential and industrial prices.

Conclusion

[32] As given in Table G.5C of the MED Energy Data File.

51. Submissions have not raised any issues which alter the preliminary views expressed in the Discussion Paper that:

- the increase in energy costs for residential and commercial users appear to have significantly exceeded the movement in the cost of new supply
- retail margins for residential users in particular appear to have increased substantially in recent years.

Appendix B

SOE restructuring and hedge market options

Purpose

This paper summarises the analysis on SOE restructuring and hedge market options contained in three documents discussed at meetings of the Electricity Technical Advisory Group ("ETAG") on 6 October 2009 and 19 October 2009.

The paper is divided into two sections:

- options to expand the competitive footprint of the SOEs through physical asset swaps and/or the exchange of hedge contracts ('virtual asset swaps'); and
- options to improve the hedge market to make it more useful to parties that are not vertically integrated, such as major industrial users, new entrant retailers, non-portfolio generators etc.

I: SOE Restructuring Options

The Discussion Paper for the Ministerial Review of Electricity Market Performance (the "Electricity Review") released in August 2009 noted that the state-owned enterprises (SOEs) have generation bases that are highly concentrated in specific regions. This contributes to regionalisation in the retail market, and weakens the level of competitive rivalry in this market. It also makes the hedge market less liquid because there are fewer primary sources of hedge contract at some grid locations (e.g. in the South Island).

A key recommendation to address these concerns was a proposal to restructure the SOEs to broaden the geographic diversity of each company's generation base. In combination with other measures[33], this was expected to strengthen competition in the retail and hedge contract markets.

While structural remedies are generally regarded as 'first best', they can be difficult to achieve for technical or other reasons. This was borne out by issues raised in submissions on the Discussion Paper on specific options (see Appendix 1 "Main issues raised in submissions on asset swap proposals").

In particular, it became clear that separation of the Manapouri scheme from the balance of Meridian's portfolio would be more complex and difficult to achieve than was thought earlier based on publicly available information.

In light of these issues, other restructuring options were considered:

- Physical asset swaps – alternative options involving the transfer power stations among SOEs, but not involving the transfer of Manapouri from Meridian; or

[33] For example, the introduction of locational hedging instruments.

- Virtual asset swaps – options that emulate the effect of physical asset swaps by a one-off exchange of long term hedge contracts among SOEs.

Specific options

The range of feasible physical 'swaps' is constrained by technical and other factors. These issues are discussed more fully in Appendix 2 "Alternative physical restructuring options". In essence, at this point, the only physical options that appear technically feasible, commercially viable and which could advance the competition objective are:

- Transfer Tekapo A and B power hydro stations from Meridian to Genesis, and transfer e3p gas-fired power station from Genesis to Meridian. In essence, this is the "Asset Swaps" proposal from the Discussion Paper, but Tekapo A & B are substituted for Manapouri and Whitehills to address Rio Tinto's concerns, and p40 has been omitted because of its small size. This is referred to as Option A in this paper; or

- Transfer Tekapo A and B power hydro stations from Meridian to Genesis, and transfer p40 gas-fired power station from Genesis to Meridian. This is the same as Option A, but p40 is substituted for e3p (given that Meridian would otherwise increase size, and it is already the largest company in generation terms). This is referred to as Option B; or

- Transfer Tekapo A and B power stations to Genesis (i.e. a one-way transfer rather than a swap per se)[34]. This is referred to as Option C.

A strawman virtual swap proposal (referred to as Option D) has been developed to compare with the three physical asset swaps noted above. The details of the strawman proposal are set out further in Appendix 3 "Description of virtual asset swap option". In brief it would entail:

- Meridian selling 1,400 GWh/year of 'South Island' energy to Genesis, and buying 1,400 GWh/year of 'North Island' energy from Genesis;

- Meridian selling 1,000 GWh/year of 'South Island' energy to Mighty River Power, and buying 1,000/GWh/year of 'North Island' energy from Mighty River Power[35].

For each SOE, the sale and purchase volume would be the same, resulting in no change to the overall business size. However, the location of buy and sell hedges would be different, broadening the range of locations where each SOE has generation/long term hedging capacity.

Relative benefits of Options A-D

This section compares the various options in terms of:

[34] If a one way transfer is contemplated, the Tekapo A and B stations could go to Mighty River Power instead of Genesis. This option has not been evaluated, but is expected to be similar to Option C.

[35] These volumes have been scaled down slightly compared to the figures in the paper circulated for the previous ETAG meeting. This scaling has been carried out following more detailed analysis of the impact on each SOE of different virtual asset swap options (see Appendix 2 for more detail).

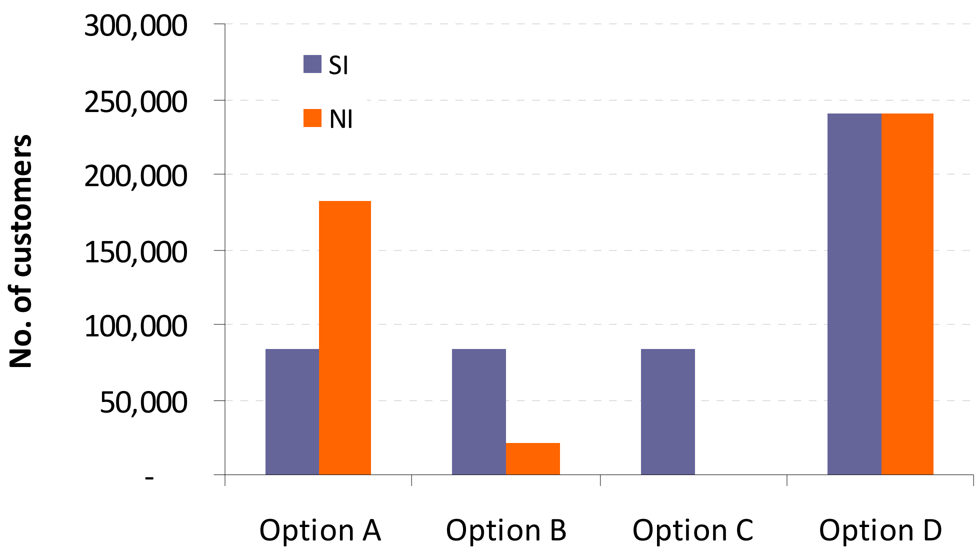
- Potential beneficial impact on competition;
- Potential beneficial impact on security/storage management; and
- Estimated restructuring costs.

Potential for increased competition

The principal expected benefit from SOE restructuring is increased competition in the retail and contracts markets. While it is not possible to precisely estimate the *actual* competitive impact of the different options due to behavioural uncertainties, it is possible to assess their relative *potential* to strengthen competition.

Two different yardsticks have been used for this purpose. The first approach assumes that the SOEs compete strongly, and focus on building their residential customer bases in 'non-traditional' areas (i.e. Genesis/MRP expand in the South Island and Meridian expands in the North Island)[36]. The number of new 'out of area' residential customers that could be supported post-restructuring differs among the options[37]. The results of this assessment are shown in Figure 13[38].

Figure 13: Potential increase in 'out of area' residential customers for SOEs



[36] In practice, SOEs expanding their regional presence are likely to target a mix of residential, commercial and industrial customers. However, the former are used as the yardstick because they are relatively homogeneous, allowing comparisons across the options.

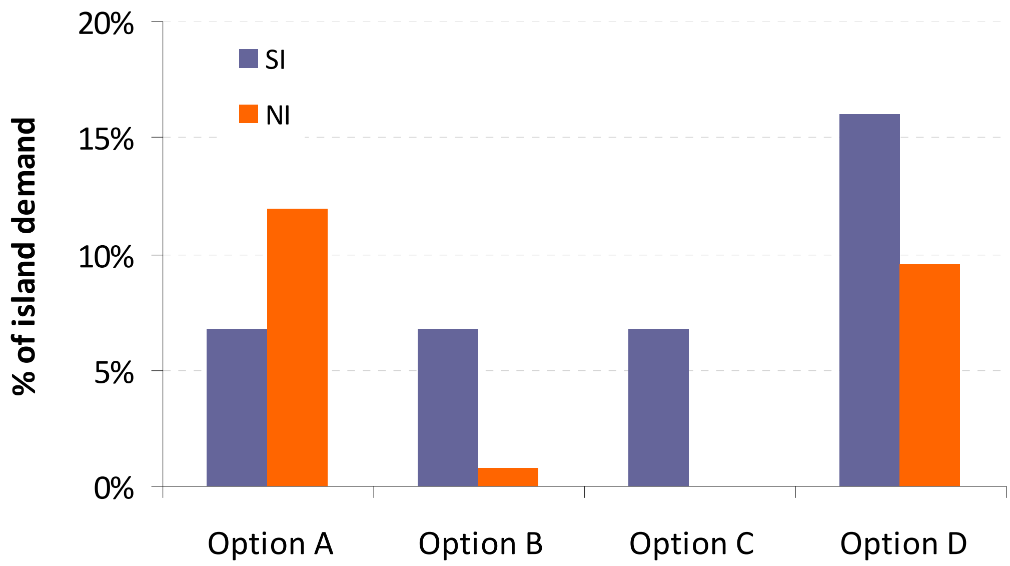
[37] Noting of course that customers that are acquired will result in reduced customer numbers for an existing retailer in that area. This may result in transfers among the SOEs, or include other retailers if there are changes in their relative shares of industrial, commercial and residential market load.

[38] In determining maximum retail capability, the charts use the lower of the figures allowed by energy and capacity requirements.

Option C has the lowest potential impact. Options A and D are similar in the North Island, but Option D has significantly greater competitive potential in the South Island (the more critical region due to current level of market concentration).

The second measure of competitive potential is to consider to the volume of energy/hedging potential that is being transferred among SOEs within each island, relative to the overall demand in that island. For example, it compares the level of output from the Tekapo stations to South Island demand. This provides a measure of how much retail/contract market potential is 'in play' under the different options. The results of this analysis are shown in Figure 14.

Figure 14: Generation volume being transferred relative to island demand



Once again, Options B and C have the lowest potential impact. Options A and D are broadly similar, but have differential effects within the two islands, with Option A having the largest impact in the North Island[39], and Option D the largest impact in the South Island.

In summary, Options A and D are strongly preferable to Options B and C in terms of potential competition benefits, and Option D is expected to be somewhat better than Option A because of its greater potential impact in the South Island. This ranking is reinforced by two other considerations:

- Option D would allow the expansion of both Genesis and Mighty River Power in the South Island, whereas other options focus solely on Genesis. This is likely to increase the competitive impact of restructuring; and

- the quantitative results for Options A & B are based on the *average* level of output from the Tekapo hydro stations. This is likely to overstate the potential competitive effects in

[39] The result differs from the previous comparison because the limiting factor in determining the number of residential customers that can be supported by e3p and p40 is peak capacity.

the South Island for these options because the station owner is likely to sell firm hedges/retail contracts based on a lower level of output to account for hydrology risk[40].

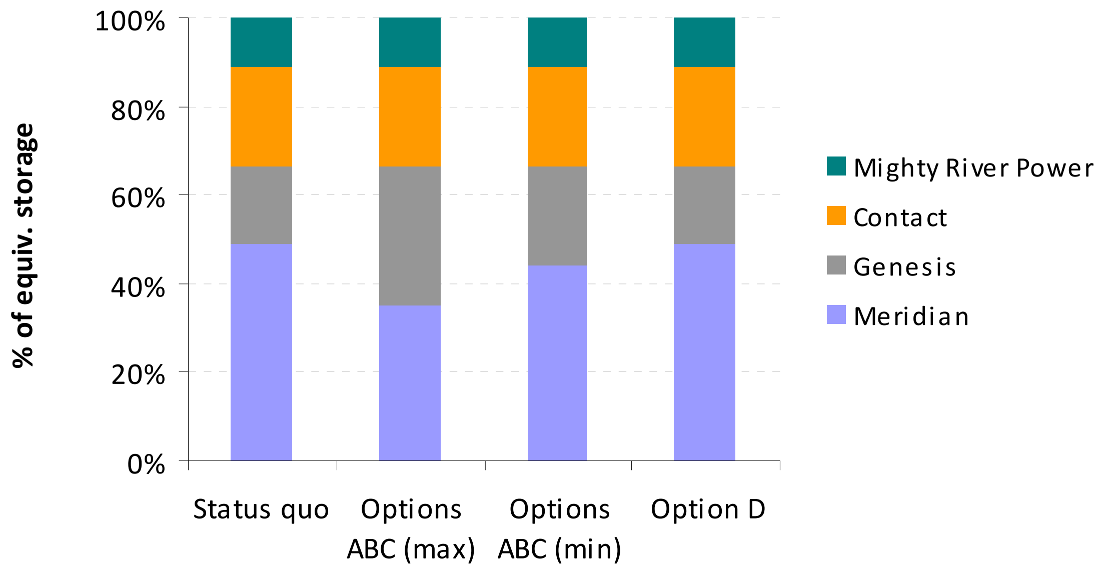
Potential for improved wholesale competition

As well as strengthening competition in the contracts and retail markets, SOE restructuring has the potential to improve wholesale market competition. This potential arises because restructuring may diversify the control of storage/flexible generation sources, thus increasing the potential for parties to contest the market.

As with retail benefits, it is not possible to precisely quantify the benefits in the wholesale market. However, an *indication* of the relative impact of the different options can be gained by comparing the control of storage/flexible generation[41] under the status quo and the other options.

Figure 15 shows the proportion of hydro storage/flexible thermal generation[42] under the control of the four largest market participants.

Figure 15: Control of hydro and flexible thermal generation



Clearly, Option D does not alter the control of storage as compared to the status quo. The physical restructuring options (A-C) are the same as each other, and could provide benefits because transfer of the Tekapo stations will move control of some storage from Meridian to Genesis.

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[40] A similar issue arises with e3p in the North Island because it is a large single point of supply. However, plant failure risk is unlikely to be correlated across thermal plants, making this easier to manage than dry year risk.

[41] In this context, only hydro reservoirs with the ability to hold storage across seasons has been included, i.e. short term storage such as headponds behind dams have been excluded.

[42] The main thermal 'reservoirs' are the coal stockpile at Huntly and the flexibility available in gas supply via contractual swing and the gas storage facility being developed by Contact at Ahuroa.

However, as explained in Appendix 2, it is not clear how much control will actually be transferred in practice. This uncertainty arises because even though Genesis would control the outlet of Lake Tekapo, most of the Tekapo hydro releases flow directly into Lake Pukaki. This lake has significant storage capacity and would remain under Meridian's control.

Meridian would undoubtedly need to take account of Genesis's Tekapo releases in framing its strategy, but may be able to use Lake Pukaki as a buffer, and deploy its own storage strategy to some extent on 'Tekapo water'. For this reason, the chart shows two values (max and min) for the physical options (Options ABC), depending on whether the full volume of Tekapo storage is attributed to Genesis or only the portion which Genesis could directly access through its own Tekapo A and B hydro stations.

The other important issue in this context is the possibility that restructuring might trigger a reopening of some resource consents conditions. At present, Waitaki catchment consents run to 2025, but Meridian considers that a change in ownership of Tekapo stations may allow other parties to successfully argue that some conditions could be reopened. Furthermore, it believes that any reconsideration of consents is likely to reduce existing flexibility in the scheme.

Assuming this view is correct, it would be likely to limit the scope for any gains in wholesale competition, through the effect of new consent constraints, or via a requirement to have a water management agreement between Meridian and Genesis (effectively re-integrating decision-making to some extent). It is also possible that there could be a net reduction in competitive potential if new constraints significantly reduced flexibility.

Expected costs / risks from restructuring

The estimated costs for the different options have been derived as follows:

- Option A - one-off and ongoing costs are expected to be broadly similar to the "Asset Swaps" proposal in the Discussion Paper[43]. However, some savings appear possible because it should be a slightly simpler transaction (fewer issues in relation to Rio Tinto obligations, no p40 transfer). The cost estimate for Option A also incorporates a lower amount for separation of control facilities for the e3p station[44]. Although one-off and ongoing costs are expected to be lower than for the "Asset Swaps" proposal, a larger contingency is included. This contingency covers the *possibility* of short-term coordination inefficiencies arising from separation of the Tekapo stations (see Appendix 1). The contingency sum is exactly the same as that used in the Discussion Paper for the "New SOE & Swaps" option, which also involved the separation of the Tekapo stations;

- Option B – these are based on the costs for Option A, except that fewer costs are expected arise from the transfer of p40 as compared to the e3p station;

- Option C – these are based on the costs for Option A, except that no costs arise for transfer of the e3p and p40 stations, and associated site separation issues;

[43] That is, the transfer of Manapouri and Whitehills to Genesis, and e3p and p40 to Meridian.

[44] This was done based on comments in Genesis's submission that e3p already has a separate "control centre".

- Option D – a lump sum of $2m - $3m has been allowed to negotiate and implement the required long term hedge contracts, plus a 20% contingency.

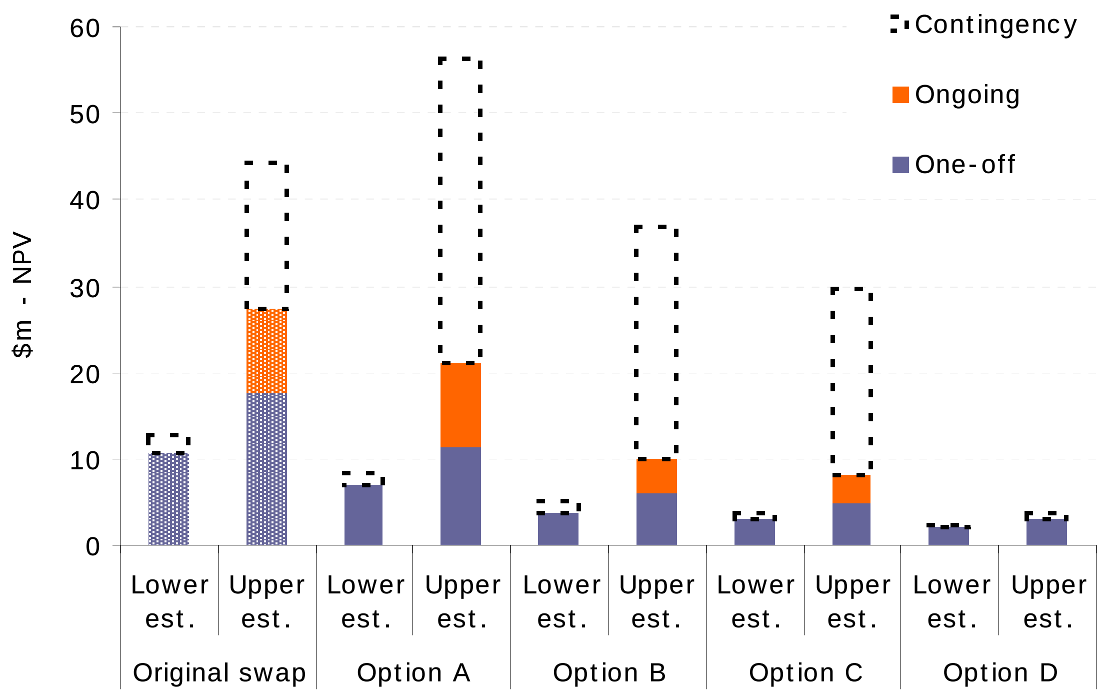
The estimated costs are shown in Table 1, compared to the costs for the original “Asset Swaps” proposal included in the Discussion Paper[45]. The same information is summarised in chart form in Figure 16.

Table 1 – Restructuring cost estimates

	Original asset swap		**Option A**		**Option B**		**Option C**		**Option D**	
			Tekapos & e3p		Tekapos & p40		Tekapos only		Virtual swap	
All figures $m NPV pre tax	Lower est.	Upper est.	Lower est.	Upper est.	Lower est.	Upper est.	Lower est.	Upper est.	Lower est.	Upper est.
One-off costs										
Asset transfer costs (legal advice etc)	6.9	10.3	5.0	7.5	3.0	4.5	2.5	3.8		
Changes to site offices/workshops etc	0.9	1.8	0.9	1.8	0.4	0.7	0.3	0.6		
Separate control centre at HLY site	2.5	5.0	0.7	1.5	0.1	0.3		-		
Transfer control of Tekapo stations			0.3	0.6	0.3	0.6	0.3	0.6		
Transfer control of Manapouri	0.3	0.6								
Negotiation of long term hedges			-	-	-	-	-	-	2.0	3.0
Total one-off costs	*10.6*	*17.7*	*6.9*	*11.4*	*3.8*	*6.1*	*3.1*	*5.0*	*2.0*	*3.0*
Ongoing costs										
Additional site & other costs		9.7		9.7	-	3.9		3.2	-	-
Total ongoing costs	-	*9.7*	-	*9.7*	-	*3.9*	-	*3.2*	-	-
Total (base costs)	**10.6**	**27.4**	**6.9**	**21.1**	**3.8**	**10.0**	**3.1**	**8.2**	**2.0**	**3.0**
Contingency costs										
Potential - gas efficiency at HLY	-	9.4	-	9.4	-	0.9	-	-	-	-
Potential - water use efficiency at TEK				16.4	-	16.4		16.4		-
Other costs (contingency)	2.1	7.4	1.4	9.4	1.4	9.4	0.6	4.9	0.4	0.6
Total contingency costs	*2.1*	*16.8*	*1.4*	*35.2*	*1.4*	*26.8*	*0.6*	*21.4*	*0.4*	*0.6*
Total (including contingency)	**12.7**	**44.2**	**8.3**	**56.4**	**5.2**	**36.8**	**3.7**	**29.6**	**2.4**	**3.6**

[45] The estimate for separating the e3p control centre from the main Huntly control centre has been reduced following confirmation from Genesis that the e3p control facility is partially duplicated already.

Figure 16 – Estimated restructuring costs



In summary:

- Options A, B and C are expected to have lower one-off and ongoing costs than the original Asset Swaps proposal, but have a higher contingency element to reflect the possibility that separation of the Tekapo stations from the Waitaki scheme could result in short term operational efficiency losses through coordination difficulties or adjustments to existing consent conditions. While this is thought to be unlikely (based on experience with earlier hydro asset restructuring), it cannot be ruled out without undertaking significant detailed analysis (which would require Meridian's cooperation);

- Option D has significantly lower expected costs than Options A-C. This stems from the fact that it avoids most of the issues associated with physical restructuring, such as renegotiation of fuel supply agreements, alteration to resource consents, staff transfers, restructuring of debt portfolios etc.

Hybrid options

The potential competition benefits from the different options are closely related to the relative volumes of generation capacity/energy that are being transferred. These volumes are larger in the virtual swap because it is governed by each SOE's overall hedge capacity, rather than the size of specific assets.

In principle, it would be possible to augment the physical swaps with additional hedge contracts to closely mirror the volumes of generation capacity/energy being transferred in the virtual asset swap option. Such additional hedge transfers would also mean that relative sizes of the SOEs would not necessarily change as a result of the physical swaps[46].

However, these advantages would need to be weighed against the relative complexities of a hybrid approach. In particular, the hybrids would not address the key risks associated with physical swaps (in particular the resource consent issues in the Waitaki catchment). They may also be more complex to negotiate than 'pure' virtual swaps, because the hedge contracts would not be symmetrical.

Overall conclusion on restructuring options

Table 2 sets out an overview of the relative benefits, costs and risks of the Options A to D.

Table 2: Relative benefits / costs / risks of options

	Option A **Tekapos to Genesis** **E3p to Meridian**	**Option B** **Tekapos to Genesis** **P40 to Meridian**	**Option C** **Tekapos to Genesis**	**Option D** **Virtual asset swap**
Retail/contracts market competition benefits in South Island	✓	✓	✓	✓✓✓
Retail/contracts market competition benefits in North Island	✓	?c		✓
Wholesale market competition benefits	Unclear	Unclear	Unclear	None
Time to implement	12 months+	12 months+	12 months+	6-9 months
Estimated level of cost $NPV	$8-56m	$5-37m	$4-30m	$2-4m
Key risks/concerns	• Largest player (Meridian) increases in size • Waitaki consent issues • Gas contract issues	• Waitaki consent issues • Little North Island benefit	• Waitaki consent issues • No North Island benefit	• Negotiation of hedge prices

On balance, of the alternatives discussed above, Option D appears the most attractive in terms of 'bang for buck'. It has the highest expected benefits and the lowest expected costs.

It is important to note that this ranking reflects the specific options described above. It is possible that these options might be modified upon closer analysis. In particular, the virtual swap has been sized at a level to maximise its expected competitive impact, and could be scaled downwards in light of discussion with SOEs. This would clearly have an impact on the relative potential benefits of the different options. However, even if the virtual swap were halved in scale, it is likely to provide more competitive impact in the South Island (the primary concern) than the options involving transfer of the Tekapo stations. Furthermore, the cost rankings would remain unchanged. For these reasons, the overall ranking appears relatively robust to refinement of the specific options.

[46] Recall that because of the size disparities between the Tekapo stations on the one hand, and either e3p (much larger) or p40 (much smaller) on the other, the proposed physical asset swaps would have a material impact on the absolute and relative sizes of the SOEs. For example, under Option A, Meridian would grow by around 16% and Genesis would shrink by around 18% in generation capability terms.

In conclusion, physical asset swaps have considerable merit where larger scale restructuring is being considered and separation issues are not unduly complex. In those cases, the scale of the expected benefits should be sufficient to cover the lumpy costs/risks associated with physical restructuring.

However, a range of technical and other factors have constrained the range of feasible physical restructuring options. Given these constraints, an approach based on virtual asset swaps appears attractive. As compared to the equivalent physical restructuring, it should deliver similar or greater benefits, have lower costs, and be quicker to implement.

II: Improving the hedge market

While SOE restructuring has the potential to broaden the SOEs' competitive footprint, it is not expected to affect the competitive position of potential new entrant or stand-alone retailers, and new entrant or non-portfolio generators.

Such parties are reliant on a workably competitive hedge market to help manage their positions. Indeed, larger customers such as industrial users that trade hedges also have a direct interest in improving hedge market arrangements. In addition, a stronger hedge market would have security of supply benefits. It would provide clearer signals about the future expected supply/demand conditions, and give electricity users greater access to risk management instruments. The latter is especially important in the context of measures to introduce improved spot price signalling in periods of market stress ("scarcity pricing").

Existing hedge market arrangements are dominated by 'over the counter' trades. These have the advantage that the terms of each trade can be tailored to meet specific needs of buyer and seller. However, by necessity, the initiator to each trade needs to reveal its requirements (and identity), and this may place the initiator (generally a buyer) at a bargaining disadvantage, especially where there are few alternative counterparties.

It is possible to buy/sell standardised hedge contracts without revealing the initiator's identity via 'blind' trading on EnergyHedge and (more recently) the ASX. However, participation on EnergyHedge is currently limited to the five main generator-retailers, and the ASX contracting trading only began earlier in 2009. The trading volume of standardised contracts is small relative to overall demand, and the principle benefit of these platforms at present is improved price discovery, rather than provision of hedge market depth. The benefits of an improved hedge market featured strongly in submissions from demand side participants.

Two broad options to improve hedge market depth have been raised:

- Regular Mandatory Offers – a requirement on major generators to regularly offer a minimum level of hedge contracts to buyers via an auction mechanism, with reserve prices set by a regulatory body; or

- Mandatory Market Maker – a requirement on major generators to post buy/sell prices for pre-defined hedging instruments (i.e. act as 'market makers'). The prices would be posted on an exchange on which any party could trade, provided it met the exchange's prudential requirements.

For the reasons set out in Appendix 4 "Hedge Contracting Options", the latter option is preferred. In brief, under the former option, a regulatory body would become directly involved in price setting (in the form of reserve prices). This carries a risk of chilling investment incentives (at least for a period). The latter approach entails much less risk in this regard, and could also be implemented more swiftly because it can be built on existing arrangements (e.g. EnergyHedge or ASX electricity contracts).

In terms of implementation, ETAG proposed an approach where industry participants (buyers and sellers) are provided with a reasonable period (say 12 months) to *develop and implement* an approach based on a Mandatory Market Maker obligation. At the end of the period, the arrangements would be assessed. Provided the arrangements were judged to be effective, no mandatory change would be imposed. However, if the arrangement was not regarded as effective, a mandatory market maker mechanism would be instituted.

Open interest as the test

ETAG suggested that the test of effectiveness be framed in terms of the level of unmatched open interest[47] in the contracts being traded on the exchange. This should be a reasonable indicator of the usefulness of the mechanism to market participants, as open interest directly measures the volume of 'live' contracts on the exchange.

However, determining the required effectiveness threshold is not clear-cut, and would be a matter of judgement. Among the relevant factors to consider are:

- the level of underlying demand for *exchange traded* hedge products that might be expected from major users/non-vertically integrated suppliers in the near term. Total physical demand from such users equates to approximately 18,000 GWh/year. Much of this will be covered by existing longer term hedge contracts. If ~5% of remaining physical demand[48] were to be met by shorter term exchange traded products, this would equate to around 500 GWh per year. Assuming such hedges are on average 18 months in duration (i.e. a mix of 1-3 years deals), this would equate to an open interest of around 750 GWh;

- the volume of trading currently occurring on existing platforms. In the eleven weeks to 30 September 2009, approximately 250 GWh of hedge product was traded through EnergyHedge and ASX. Assuming the average duration of trades is one year, this would suggest open interest is currently around 1,200 GWh; and

- the experience with establishment of exchange traded hedge products in Australia[49]. The open interest in traded electricity derivatives has risen from zero in 2002 to 50,067 contracts on 12 October 2009. This level of open interest represents 165 TWh of contract

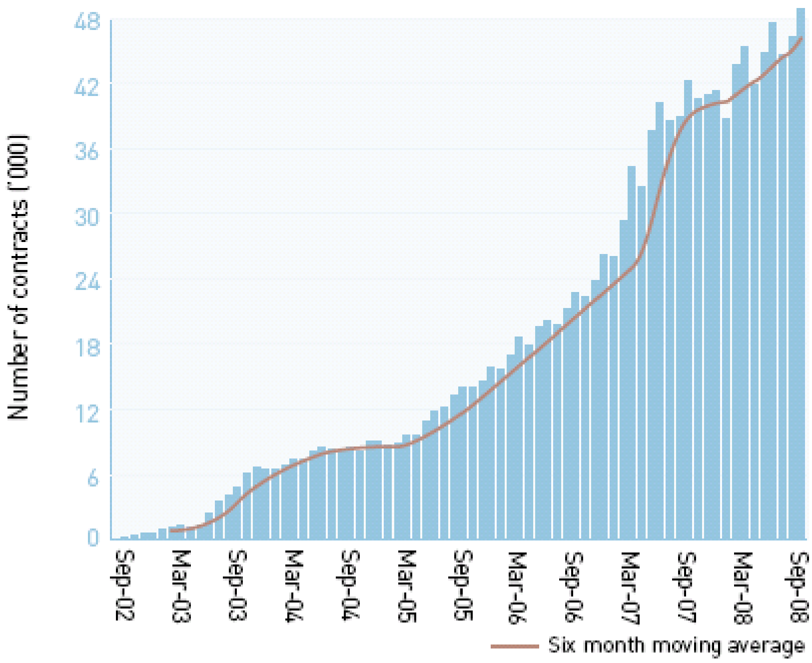
[47] Open interest refers to the total number of contracts that are held by market participants at the end of the day. Thus, if 200 futures contracts had been bought and sought through an exchange (and each contract was for 1 MW for June quarter 2010), open interest in that contract would be 200. Unmatched interest includes only those contracts for which parties do not hold the matching contract to offset it. In other words, it excludes the contracts for which the beneficial owner holds both the bought and the sold.

[48] Excluding the portion met by longer term contracts – thought to be around 6,000 GWh/year.

[49] Strictly speaking the mainland regions of the Australian National Electricity Market.

cover (compared to annual physical demand of over 200 TWh). The growth in open interest is shown in Figure 17. It has taken around seven years for open interest to reach approximately 75% of underlying physical demand. Assuming a similar rate of increase occurred in New Zealand, open interest might be expected to be around 5-10% of aggregate demand[50] (i.e. 2,000-4,000 GWh) after the initial 12 months of trading. However, it should be emphasised that vertical integration is less prevalent in Australia, meaning that there is a higher underlying demand for such products in that market.

Figure 17: Open interest – Australian NEM traded electricity derivatives



Source: Australian Energy Regulator

Weighing these various factors, a threshold unmatched open interest of around [2-3,000] GWh would appear reasonable. While no measure is perfect, it should provide a pretty good yardstick of the state of hedge market development.

It would also be desirable to assess a number of qualitative indicators, such as:

- the number of parties that participate in the market[51];
- the type of parties that participate – especially the level of interest by parties other than the five main vertically integrated suppliers;
- the availability of pricing information for parties to use in negotiation of 'over the counter' (i.e. bespoke) deals.

Provided sufficient progress has been made by say October 2010, no mandatory market maker obligation would be imposed. If progress is not judged to be sufficient, a mechanism with a mandatory market maker obligation would be imposed via regulation.

[50] This assumes trading volume and open interest follow a similar trend.

[51] For example, the open interest threshold might be met, but there might be only two participants using the exchange. This is obviously unlikely, but it illustrates the difficulty of devising a simple test.

Appendix 1:

Main issues raised in submissions on asset swap proposals

The Discussion Paper recommended that consideration be given to three SOE restructuring options to increase competition in the retail and wholesale electricity markets. Following comments by the Minister regarding the options, submissions mainly focused on Option 3 (Manapouri/ White Hill and e3p/p40 swap).

The following table summarises Discussion Paper Option 3 and alternatives proposed by submitters.

Option	Summary
Discussion Paper Option 3 (***Option 3***)	• Transfer Manapouri and White Hill wind farm from Meridian to Genesis • Transfer e3p and p40 gas turbine plants from Genesis to Meridian • Assign the Tiwai contract to either Genesis or Meridian and put a backup contract in place with the other
RTANZ[52] and Genesis 3B proposals (**RTANZ / Genesis 3B**)	• Transfer the three lower Waitaki stations from Meridian to Genesis (i.e. Benmore, Aviemore and Waitaki stations)[53] • Transfer e3p and p40 from Genesis to Meridian
Genesis 3A proposal **(Genesis 3A)**	• Transfer White Hill and Tekapo assets from Meridian to Genesis (i.e. Lake Tekapo and Tekapo A and B stations) i.e. no thermal asset transfers to Meridian.

Meridian and Energy Link also commented on the transfer of Tekapo assets (as in Genesis 3A). Meridian expressed concern, primarily about loss of operational efficiency. Energy Link considers that, in addition to South Island retail competition benefits, there would be wholesale market benefits from weakening Meridian's hydro storage dominance.

RTANZ and Genesis appear to have misinterpreted Option 3 as proposed in the Discussion Paper; assuming the Tiwai contracts would rest solely with Genesis. They therefore underestimated the impact of Option 3 on retail competition in the South Island. However, it is clear that RTANZ opposes Option 3.

The RTANZ/Genesis 3B alternative would in principle promote retail competition in the South Island with a reasonable balance of wholesale market shares net of Tiwai obligations.

52 Rio Tinto Alcan New Zealand Limited.

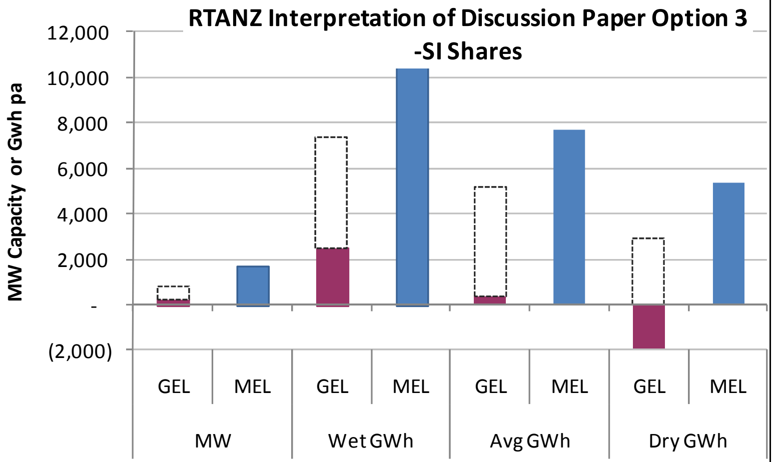
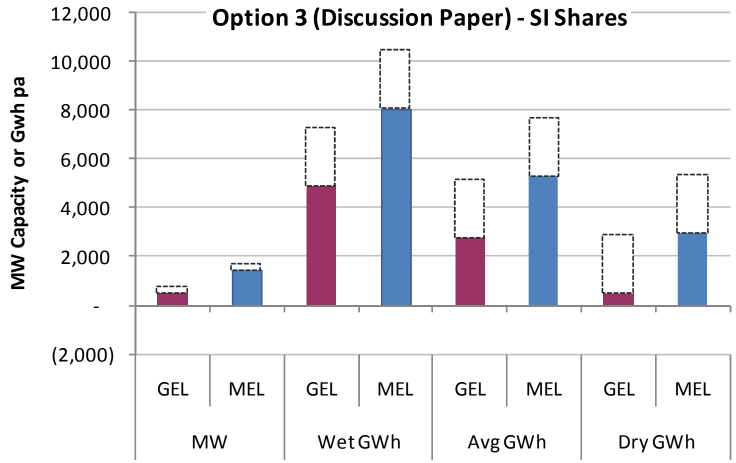
53 Under Option 3B in Genesis' submission, White Hill wind farm would also transfer from Meridian to Genesis. RTANZ considered it should stay with Meridian given proximity to Manapouri.

It would avoid Tiwai contract issues. However, separating the three lower stations from the rest of the Waitaki system would be problematic. These stations have very limited storage, are closely coupled hydraulically to upstream stations, are strongly reliant on releases from upstream storage controlled by Meridian and are bound by downstream minimum and ramping rate flow consent conditions. Consenting issues could also be difficult to resolve in relation to which party is best able to manage compliance with key conditions over which both would have influence.

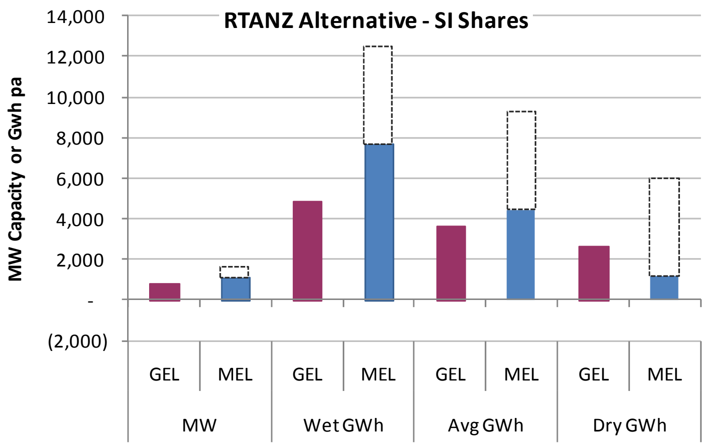
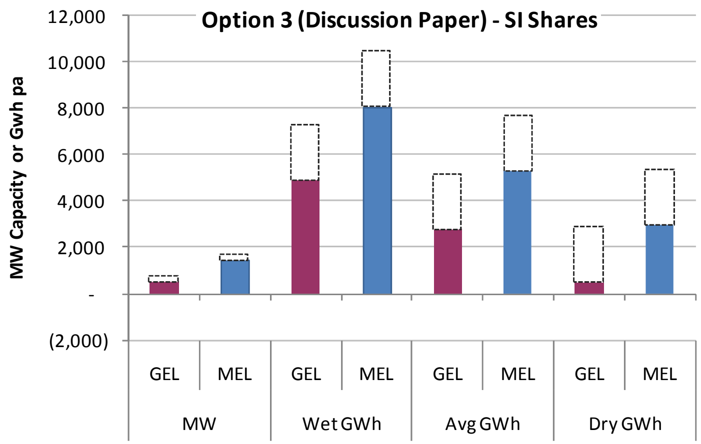
The possibility of transferring Tekapo assets to Genesis (Genesis 3A) has some merit. It would reduce Meridian’s dominant position in relation to hydro storage and would increase South Island retail competition, albeit to a lesser extent than RTANZ/Genesis 3B or Discussion Paper Option 3. It would not directly involve the Tiwai contract and, apart from resource consenting issues, would largely be a transfer of assets between SOEs with limited third party involvement. There may be some risk of technical efficiency losses at times but in general Lake Pukaki (40% of New Zealand’s storage) decouples day to day operation of the Tekapo system from the rest of the Waitaki system.

The transfer of thermal assets from Genesis to Meridian would provide greater benefits than Genesis 3A which, by itself, would not directly increase North Island competition.

RTANZ

Para	Summary of RTANZ views	Comment
120	Option 3 [Discussion Paper] will not achieve the objective of increasing retail competition because it does not properly account for the Tiwai contracting arrangements and hydrology (wet/dry years).	Under Option 3, as described in the Discussion Paper, either Meridian or Genesis would hold the Tiwai contract with contractual backup from the other. RTANZ's interpretation of the proposal appears to be that the Tiwai contract obligations would rest entirely with Genesis. The left hand chart below shows Genesis and Meridian capacity and average annual supply under RTANZ's interpretation[54]. The adjacent right chart shows corresponding assumptions for the Discussion Paper proposal. In each case, the effect of netting off Tiwai obligations is highlighted. Rio Tinto's interpretation is considerably different.
123/4	Option 3 fails to account for Tiwai contract sales, producing a very dominant position for Meridian and, if transmission constraints bind, considerable dry year exposure for Genesis. It is therefore unlikely that Genesis would have any appetite to become a major retail competitor to Meridian.	
		
128/	The Discussion Paper objectives would be better met by an	From a market share perspective, the RTANZ proposal could enhance

[54] Built up using underlying Discussion Paper assumptions in each case for consistency.

Para	Summary of RTANZ views	Comment
129	alternative asset swap whereby: • The last three Waitaki hydro system stations (Benmore, Aviemore and Waitaki) would be transferred to Genesis (instead of Manapouri and White Hill) • Meridian would retain the Tiwai contracts (without backup arrangements) • e3P and P40 would transfer to Meridian (as proposed in Discussion Paper Option 3) The alternative proposal produces relatively balanced asset portfolios across the three SOEs.  	retail competition in the South Island. As shown in the charts below, under the RTANZ proposal (left) Genesis' and Meridian's South Island shares would be more balanced than under Option 3 (right) as proposed in the Discussion Paper. The RTANZ proposal would also avoid the need for formal Tiwai back-up arrangements between Genesis and Meridian. 

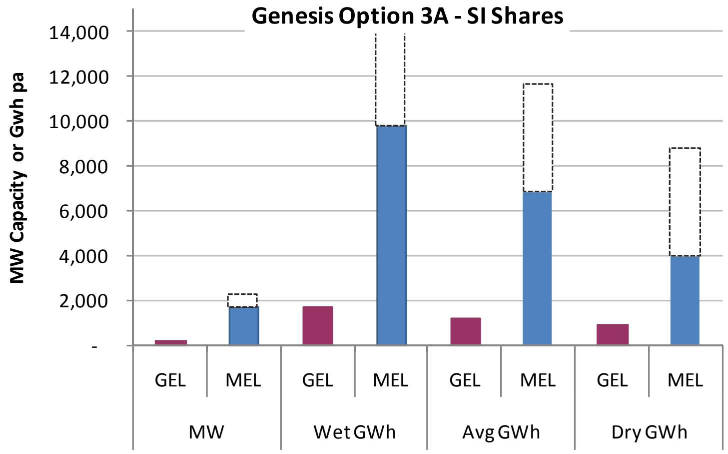
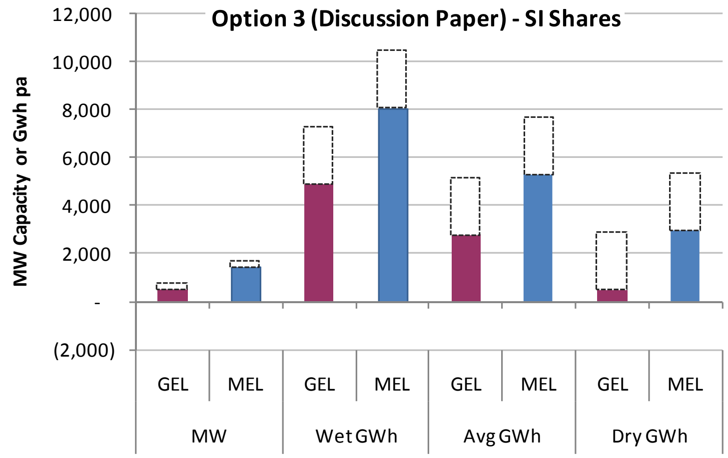
Para	Summary of RTANZ views	Comment
134	The alternative swap proposal is a relatively straightforward option to meet Discussion Paper objectives although a number of issues, including technical efficiency and consenting risks, would need to be worked through.	The RTANZ proposal has a number of inherent risks that would need to be considered very carefully including: • Loss of technical efficiency from separating stations downstream of Lake Pukaki from the main storage lakes. These stations are tightly coupled hydraulically and have minimal intermediate storage[55]. This means Meridian would largely determine Genesis' day to day water availability including potentially its ability to maintain lower Waitaki flow requirements (minimum flows, flushing flows, ramping rates etc). At worst, Genesis could largely become a 'tolling operation' for Meridian. (A description of the Waitaki system is included as background later in this Appendix). • It is unlikely that the RTANZ variant of leaving Waitaki station with Meridian and allocating Ohau C to Genesis would help (and it may worsen short term coordination). • Consenting issues would also need to be addressed including how to assign existing conditions between two companies, noting both would be able to influence compliance (for example Lower Waitaki minimum flows, flushing flows etc). • Under the RTANZ proposal, Meridian would retain the bulk of South Island storage and gain thermal plant, increasing its share of energy storage flexibility within the system. Under Option 3 in the Discussion Paper, storage/ energy supply flexibility would be reallocated.

55 Lake Benmore has some storage but the station efficiency suffers when the lake level is cycled.

Genesis

Para	Summary of Genesis view	Comment
182 (last bullet), 193, 194	Transferring Manapouri to Genesis without other structural adjustments would not improve retail competition in the South Island due to that plant's other contractual commitments.	Under Option 3 (Discussion Paper), the Tiwai contract would be allocated to Meridian or Genesis with the other holding a backup contract. It is unclear what contractual impediments there might be to establishing such arrangements, noting RTANZ is unwilling. However, Option 3 was designed to support retail competition, taking account of Tiwai commitments. See earlier comments on RTANZ's submission.
197	Proposes two alternative options: • Transfer of Tekapo stations and White Hill wind farm from Meridian to Genesis (with no thermal assets to Meridian) • Transfer lower Waitaki stations (as in RTANZ alternative) and White Hill to Genesis and e3p and p40 to Meridian	i.e. Option 3A in Genesis' submission. i.e. Option 3B in Genesis' submission, which is essentially the same as the RTANZ proposal[56] (hence called *RTANZ/Genesis 3B* in this paper).
198-200	Genesis Option 3A: • minimal implementation costs, preserve Meridian's renewable-only branding • primary benefit of enhanced South Island competition • may improve dry year risk management to some degree • minimal loss of operational efficiency on Waitaki River • would not directly alter North Island retail competition but less policy concern as more significant competitors in North Island	Genesis Option 3A (left chart below) would be less effective in stimulating retail competition than Discussion Paper Option 3 (right chart). It would provide less South Island competition benefits and not contribute directly to North Island competition. The same could be said of wholesale competition, although significant South Island energy storage (Tekapo) would be reallocated. Separating ownership of Tekapo from the rest of the Waitaki system would be less complex and less risky than separating the lower Waitaki stations (RTANZ/ Genesis 3B). In particular, Pukaki provides a large storage buffer between the Tekapo stations and the rest of the scheme. Attachment One includes further discussion. Genesis Option 3A could be enhanced by the transfer of thermal assets (e3p and p40) from Genesis to Meridian, increasing North Island competition.

56 As proposed by RTANZ except that under the RTANZ proposal, White Hill would remain with Meridian given proximity to/ support from Manapouri.

Para	Summary of Genesis view	Comment
	 	

Para	Summary of Genesis view	Comment
201-2	Genesis Option 3B[57] • more closely resembles Option 3 in the Discussion Paper • may cause greater operational efficiency losses than [Genesis] Option 3A (limited Benmore storage capacity and high percentage of inflows controlled by upstream stations) • may not stimulate South Island competition as effectively as Option 3A • more costly than Option 3A (more complex Waitaki split, site split at Huntly and gas market complexities) • potentially feasible and may warrant further investigation	See earlier comments on RTANZ's alternative proposal.
204	Preliminary view is that transfer of assets is feasible and would be likely to enhance competition but options warrant further analysis from policy and due diligence/commercial perspectives.	
205-6	Discussion Paper provides a reasonably accurate high level assessment of asset transfer issues at a high level including assessment although some may be over-stated (e.g. e3p control centre is already separate from Units 1 to 4 and could quite readily be owned and operated independently).	These comments helpfully provide increased confidence regarding implementation issues in separating the ownership of assets at the Huntly site.

57 Same as the RTANZ proposal except that White Hill would remain with Manapouri/ Meridian under the RTANZ option.

Meridian

Para	Summary of Meridian view	Comment
113	Option 3 [Discussion Paper] will require various risks to be addressed and costs are likely to be more significant than suggested in the Discussion Paper.	The issues raised by Meridian have been addressed in previous restructuring exercises. The Discussion Paper based cost estimates on previous restructuring, such as the ECNZ splits. Meridian's view on costs appears different to that put forward by Genesis (see above).
116	Aware that other parties have suggested swapping Tekapo A and B power stations. Not considered in detail but a number of hydrological features would either need to be addressed, or water efficiency losses incurred. e.g: • ability to reduce spill and store water by reducing Tekapo generation when run of river flow (Ohau/Ahurihi) is high • in low demand periods (e.g. over Christmas), Tekapo generation is normally shut down as generation needs can be met from must run flows and Pukaki releases needed for lower Waitaki River minimum flows limits • Lake Tekapo inflows are on average 63% of Lake Pukaki inflows. However, Tekapo storage is only 30% of Pukaki storage so the inflow to storage relationship is quite different. Similarly, there are differences in the maximum canal flows – Tekapo canal maximum is 130 cumecs, whilst Pukaki canal maximum flow is 560 cumecs • this means management of Lake Tekapo levels requires long term planning and certainty Different operators for Tekapo A and B, relative to the rest of the Waitaki Chain, could lead to a more inefficient operation, increased spill and potentially consent breaches.	Separating Tekapo assets from the rest of the Waitaki scheme has been suggested by Genesis (Genesis 3A) and Energy Link in their submissions. This was also considered as part of Discussion Paper Option One. It is possible that there could at times be an increased risk of technical efficiency losses. The sort of issues raised by Meridian would need to be managed through market offers/ pricing rather than internally by Meridian. Having two storage lakes in separate ownership would reduce Meridian's dominant position in relation to flexible energy storage and provide contestable views as the value of storage in the market. As noted in commenting on Genesis' submission, transferring the Tekapo assets to Genesis would also improve retail competition in the South Island and (if thermal assets were transferred to Meridian as well) the North Island. Further discussion on the separation of Tekapo assets can be found in Attachment One.

Energy Link

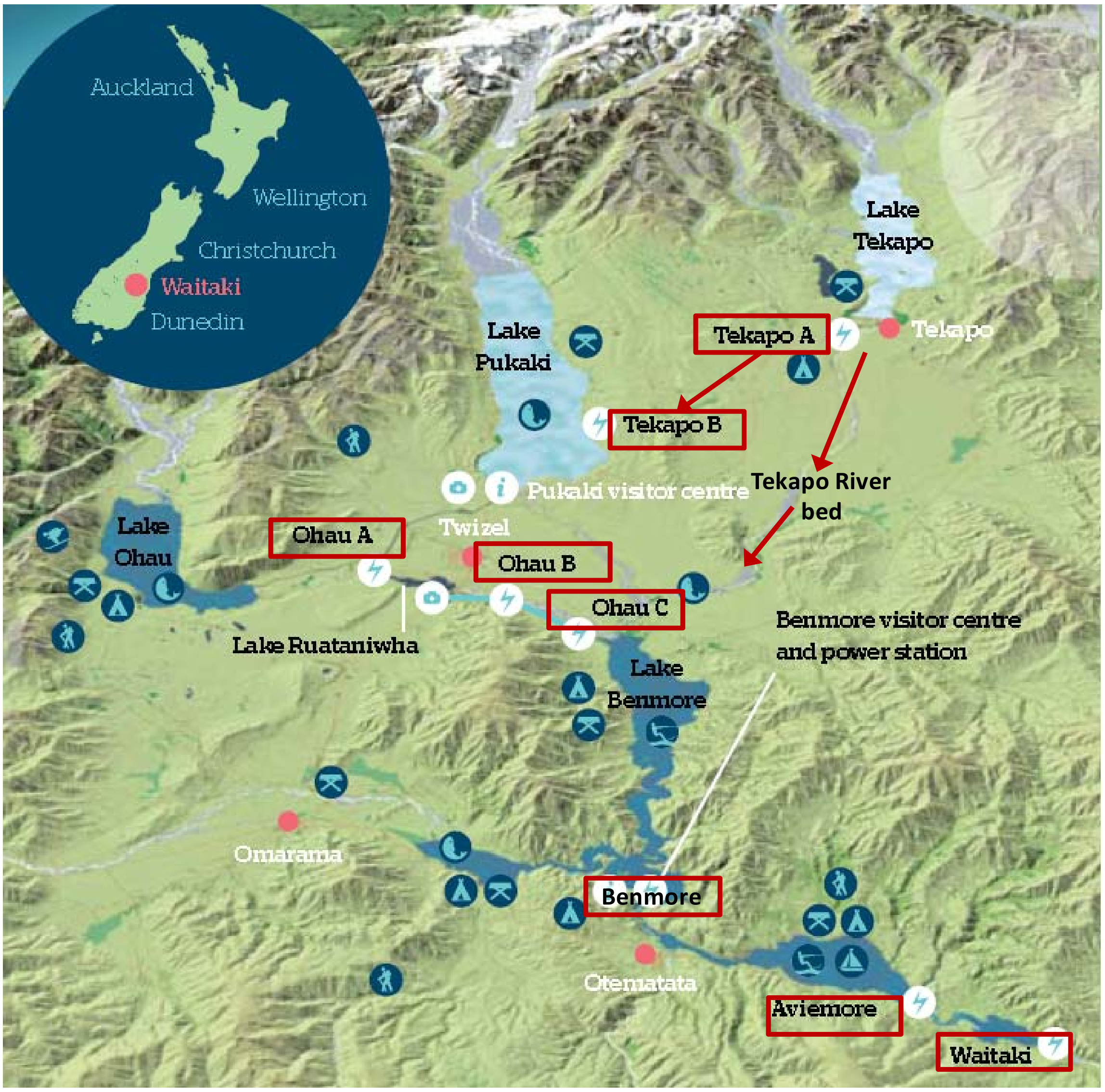
Para	Summary of view	Comment
Section 5	Transferring ownership of Manapouri is not a viable option as it has limited storage and regularly generates at less than Tiwai requirements.	Physically, Tiwai load is supplied from the system and relies on Clutha and Waitaki supply. Under the Discussion Paper proposal Option 3, backup contractual arrangements would be implemented. However, it is likely that RTANZ would strongly resist transferring Manapouri to Genesis.
Section 5	Could reduce Meridian's influence on water values and security of supply by transferring Tekapo storage and generation to another generator. Would also enable an additional retailer to have a more active role in the South Island. Control of Tekapo storage and operation of the Tekapo stations is not intrinsic to the operation of the rest of the Waitaki hydro system. This is because the storage capacity in Lake Pukaki is sufficient to buffer inflows from the Tekapo system. Lake Pukaki can therefore absorb variable inflows from the Tekapo system excepting extreme or flood conditions, which is essentially no different from the current situation. If another generator owned and operated the Tekapo system it could be expected to control the lake storage in a similar manner to that which Meridian does now, except that it could take a different tactical view of the markets and modify its actions depending on how Meridian was operating the storage in Lake Pukaki. This diversity of view would have a positive impact on the overall security of supply and on wholesale electricity prices.	Generally agreed. See earlier comments regarding the separation of Tekapo assets (Genesis Option 3B) and discussion in Attachment One.

Waitaki Hydro System

The Waitaki hydro system is depicted schematically below. It comprises eight power stations, highlighted by the red boxes, and holds approximately 60% of New Zealand's hydro storage capacity (in Lake Tekapo and Lake Pukaki). The general flow of water is:

- Releases from Lake Tekapo storage flow through Tekapo A and B stations into Lake Pukaki
- Releases from Lake Pukaki and largely uncontrolled flows from Lake Ohau flow through the three Ohau stations into Lake Benmore
- Benmore water flows through Benmore, Aviemore and Waitaki power stations then down the Lower Waitaki River

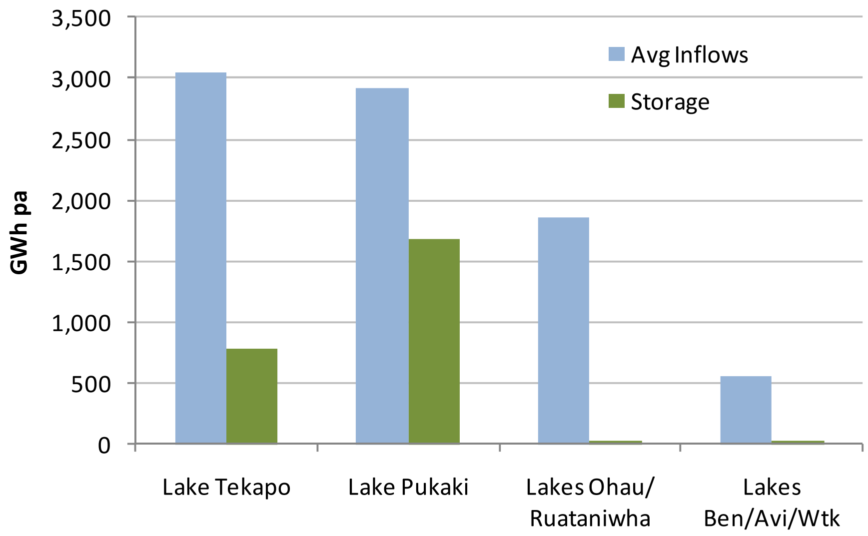
Waitaki hydro scheme overview



Separating Lower Waitaki Assets (RTANZ/ Genesis 3B)

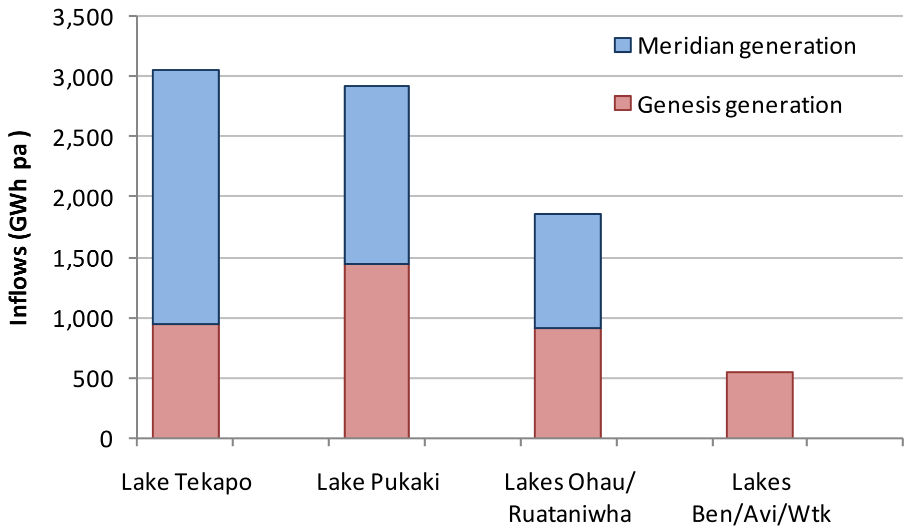
Under the RTANZ/Genesis 3B proposal, the three lower Waitaki stations (Benmore, Aviemore and Waitaki) would be transferred from Meridian to Genesis. That would leave Meridian in control of Lake Tekapo and Lake Pukaki, over 60% of New Zealand's hydro storage capacity (plus Manapouri/Te Anau storage). Genesis would be dependent on Meridian releases from storage for the majority of its generation. This can be seen in the following chart which shows average inflows and storage capacities within the Waitaki scheme. The data is shown in terms of potential energy supply that could be generated within the scheme if all the inflows could be fully utilised. i.e. ignoring spill. For example, Lake Tekapo storage capacity of approximately 780 GWh represents the amount of electricity that could be generated from the water stored in the lake passing through the scheme. i.e. through the Tekapo stations into Lake Pukaki, then on through the Ohau stations and then though the lower Waitaki stations (Benmore/ Aviemore/ Waitaki).

Waitaki Hydro System Storage Capacities and Annual Average Inflows



The following chart re-presents the data from the above chart to show, under the RTANZ/Genesis 3B proposal, the average contributions from inflows passing through Waitaki system storage to Meridian and Genesis annual generation respectively. For example, the pink shaded portion of the left most column shows that almost 1,000 GWh of energy will be produced on average from inflows that pass through Lake Tekapo (controlled by Meridian).

Waitaki Hydro System Inflow Contributions to Genesis and Meridian Annual Supply



Thus, although all inflows into the Waitaki hydro system ultimately flow through its stations, including upstream spill, Genesis would have minimal storage of its own with which to manage these inflows. In annual energy supply terms, around 70% of inflows into the Waitaki hydro system pass through Lake Tekapo and Lake Pukaki, storage which would be controlled by Meridian. Lake Benmore has a small amount of storage but it tends to be operated at a relatively constant level to maintain station head levels to avoid efficiency losses.

Separating ownership of stations within a river chain system is inherently more complex than for stations above and below seasonal storage lakes. For example, the Waikato and Tongariro hydro systems are separated by Lake Taupo and operated by Mighty River Power and Genesis respectively. Prior to being split in 1999, ECNZ operated both systems.

Separating Tekapo Assets (Genesis 3A)

Genesis proposed an alternative to Discussion Paper Option 3 (*Genesis 3A*) whereby Lake Tekapo and the Tekapo A and B stations would be transferred from Meridian to Genesis. Although Meridian has expressed some concerns about this possibility, it would be significantly less problematic than separating the lower Waitaki stations as proposed by RTANZ and supported to an extent by Genesis (*RTANZ/ Genesis 3B*).

Resource consent issues would still need to be resolved, given Meridian currently holds consents for the entire scheme as a package. However, on a day to day basis Lake Pukaki effectively decouples Tekapo operation from the rest of the scheme (as in the Tongariro/Taupo example noted above). i.e. water released from Lake Tekapo storage flows under normal circumstances through Tekapo A, and via the Tekapo canal system, Tekapo B power station and then into Lake Pukaki. The Tekapo stations are matched hydraulically by the canal so they are operated in tandem. On a day to day basis, from a water management perspective, the Tekapo stations can therefore generally be operated independently of the rest of the Waitaki scheme because Lake

Pukaki is a seasonal storage facility. It is the country's largest hydro storage reservoir, holding about 40% of national storage in energy supply terms.

Transferring Lake Tekapo to separate ownership carries some risk of loss of medium term coordination efficiency. However, it would increase South Island competition. There would be another significant retail competitor in the South Island.

Further, the perceived value of water in hydro storage lakes has a significant bearing on the market, in terms of security and price. Separating Tekapo from Meridian would weaken Meridian's control of flexible energy resources and increase diversity of views regarding water values.

Under Genesis 3A, there would be no transfer of thermal assets to Meridian. Transferring thermal assets (e3p and p40 gas turbines) from Genesis to Meridian would also assist North Island competition and better balance portfolios with respect to storage and thermal support.

Appendix 2:

Alternative physical restructuring options

Two of the three SOE restructuring options proposed in the Discussion Paper were ruled out by Ministers[58]. Following consideration of consultation submissions, Option Three has also been discounted, largely because of the difficulties associated with the Tiwai smelter supply arrangements.

Option Three would have involved the transfer of Manapouri and White Hill wind farm from Meridian to Genesis in exchange for e3p and p40 with Tiwai contract obligations effectively being split between the two companies. The focus has now shifted to the fallback option of transferring Tekapo assets to Genesis and e3p or p40 to Meridian. The possibility of transferring just the Tekapo assets was also raised in submissions.

This Appendix discusses the main issues that would need to be addressed in order to transfer the above assets, and considers potential market impacts.

Asset separation issues

Table 3 provides a summary of the assets under consideration.

Table 3: Summary of assets

Plant	Tekapo A and B	P40	E3p
Type	Hydro	Open cycle GT	Combined cycle GT
Fuel	Storage releases	Gas	
Capacity	185 MW[59]	48 MW	400 MW
Supply capability	1,020 GWh pa (mean inflows)	210 GWh pa (50% load factor)	2,980 GWh pa (85% load factor)
Location	Upper Waitaki canals	Huntly site	
Grid injection	A: Tekapo - Timaru 110 kV B: Benmore – Islington 220 kV	Huntly 220 kV switchyard	

Issues that would need to be addressed in order to separate the Tekapo and e3p or p40 assets for transfer have been discussed in previous papers and are summarised in Table 4 below.

[58] Option One (new SOE plus asset swap) and Option Two (transfer Huntly to Solid Energy plus asset swap)

[59] Tekapo A is 25 MW (single unit) and Tekapo B 160 MW (2 units).

Table 4: Asset separation issues

Issue	Tekapo A&B	P40	E3p
RMA	Split out from Waitaki consents	Split out from Huntly consents envelope	
Gas supply		Allocate Genesis entitlements between Meridian (e3p/p40) and Genesis (Huntly 1-4). Developments?	
Control centre	Separate control from Twizel	Establish separate facility (remote?)	Establish on-site fully separated facility
Common facilities	Stores etc; common data/ systems	Site agreements (workshops, stores, security etc), common services	
Resourcing	Genesis has hydro expertise but would need some local staff	Meridian thermal expertise would need to be increased. Potential for some duplication (some operations/ technical staff work on all Huntly units)	
Technical efficiency	Medium term coordination efficiency? Short term loss/ spill coordination?	E3p/p40 operation probably similar to now Possible short term efficiency fuel switching loss	

Each of these issues would need to be examined fully to confirm feasibility and costs but it is unlikely that any are fundamental impediments to separation. Note that in its submission, Genesis indicated that it considers the Discussion Paper cost estimates for separating out e3p and p40 were possibly overstated, noting that e3p already had separate control facilities[60].

Resource consent risks are difficult to assess but being an integrated suite of many conditions granted as a single package, disentangling Tekapo consents from the Waitaki consents package is likely to be difficult. Meridian indicated[61] that it considers this would in effect trigger reconsenting and carry significant risk of loss of flexibility.

Based on previous analysis of these issues, and the above information, the following table provides a high level indication of the degree of difficulty and potential risks.

[60] Currently e3p is controlled from the main Huntly control room along with the coal units but there is a second control panel on site reducing efforts to establish a fully independent control room for e3p.

[61] And provided independent legal advice.

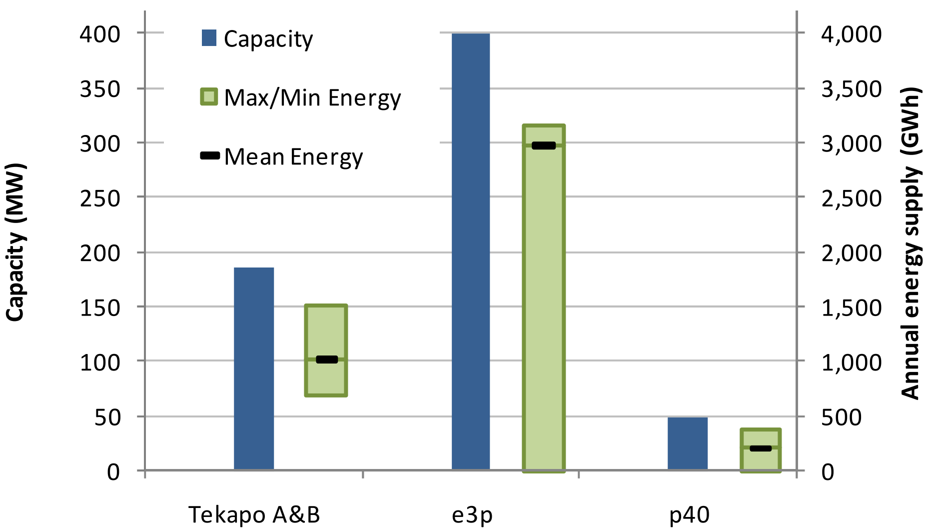
Table 5: Assessment of relative effort and risks

Issue		Tekapo A&B (Lo – Hi)	p40 (Lo – Hi)	e3p (Lo – Hi)
RMA	Effort			
	Risk			
Gas supply	Effort			
	Risk			
Control centre	Effort			
	Risk			
Common facilities	Effort			
	Risk			
Resourcing	Effort			
	Risk			
Technical efficiency	Effort			
	Risk			

Market share implications

Figure 18 shows the generating capacity and energy supply capabilities of the Tekapo and thermal assets under consideration[62].

Figure 18: Asset technical capabilities



e3p capabilities are significantly greater than for the Tekapo asset capabilities, which are in turn significantly greater p40 capabilities.

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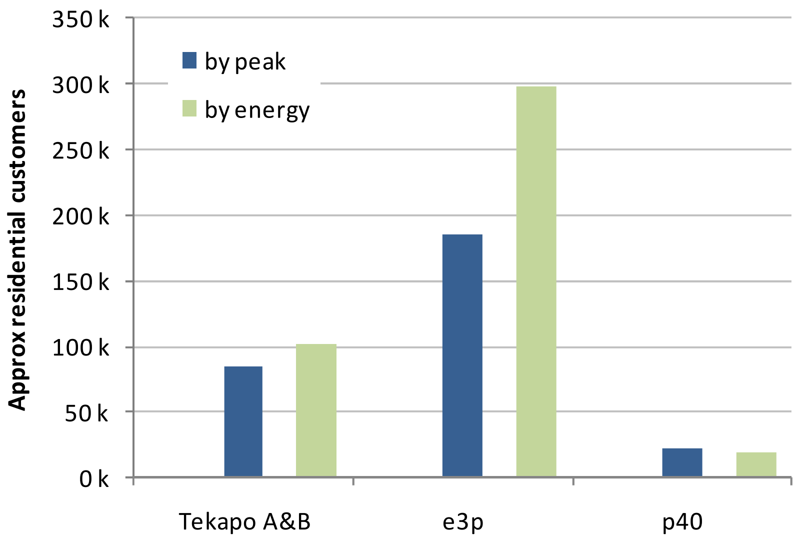
62 The energy supply range for Tekapo reflects wet and dry year capabilities. The corresponding ranges for e3p and p40 reflect maximum capability assuming each plant operates at 90% load factor. The mean thermal capability is based on load factors of 85% for e3p and 50% for p40 (its approximate historical average).

In relation to retail impacts, Figure 19 provides estimates of the number of residential customers that equate roughly to asset capabilities. i.e. the number of customers with combined peak demand equal to generating capacity and annual combined energy demand equivalent to mean energy supply capability[63].

Figure 19: Equivalent residential customer numbers



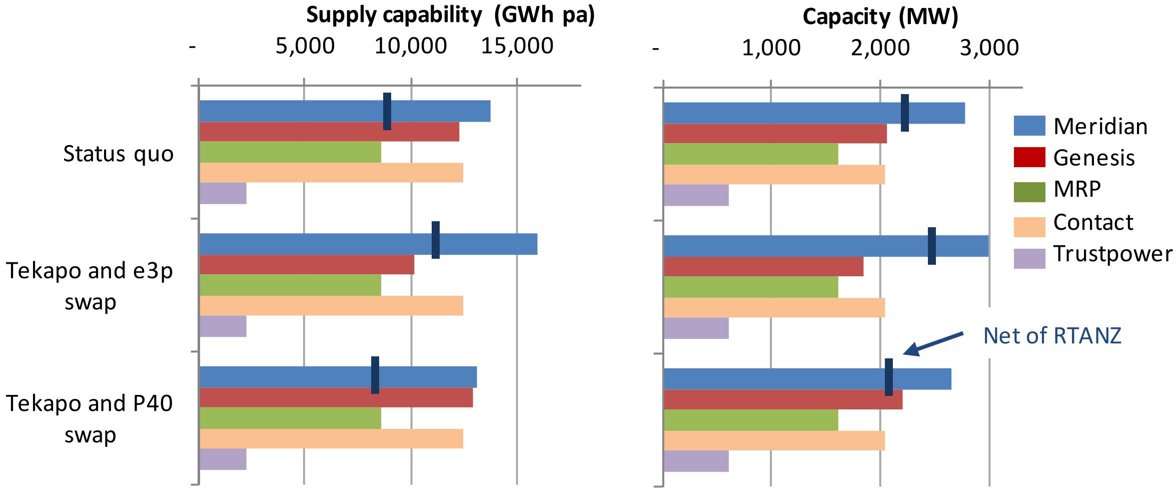
Tekapo A and B generation equates to approximately 85,000 to 100,000 customers. That represents around 20% of South Island residential customers and approximately 10% of South Island consumers excluding Tiwai. In practice, the numbers are likely to be lower given dry year risks (annual Tekapo generation in a very dry year is approximately 30% lower than mean levels).

In contrast, in terms of equivalent residential customers, respective p40 capabilities are equivalent to around a quarter of Tekapo capabilities. The corresponding figure for e3p is two to three times that for Tekapo assets. While the North Island market is larger, if e3p and Tekapo assets were exchanged, Meridian's national retail base could grow of the order of 200,000 equivalent residential customers at Genesis' expense.

The impact on wholesale market capabilities can be seen in Figure 20. It shows energy supply capability (left chart) and peak capacity (right chart) by company. Meridian's capabilities net of Tiwai contract obligations are also highlighted.

63 Based on an average customer demand of 10,000 kWh per annum with an (after diversity) peak of 2.2 kW.

Figure 20: Comparison of <u>national</u> wholesale market capabilities by company



Comparing upper (status quo) with the lower (swap) charts in Figure 20 indicates that the e3p/Tekapo swap would extend Meridian's wholesale position at Genesis' expense and the p40/Tekapo swap would have an opposite, but smaller, effect.

In terms of net energy supply capability (i.e. net of Tiwai obligations), at face value the e3p/ Tekapo swap would appear to provide a better balance between the main generators. However, given Huntly's marginal role, Genesis' average energy supply will be less than the technical capability shown above (which includes approximately 6,500 GWh for Huntly). In 2008, a dry year, Huntly units generated less than 4,500 GWh. In contrast, e3p will tend to be base loaded, operating close to the technical capability assumed in the above chart. Meridian's overall size (rather than net of Tiwai obligations) is probably a better measure of its ability to influence wholesale market outcomes.

On the same basis, swapping p40 and Tekapo swap would grow Genesis' overall share at Meridian's expense and there would be a better balance of national portfolios.

Figure 21 below shows, on the same basis as the previous chart[64], how South Island wholesale market technical capabilities would alter for each company. While Genesis would gain a significant South Island presence, Meridian would retain its dominant position.

[64] As transferring P40 *or* e3p makes no difference to South Island capabilities, they have been grouped together for simplicity.

Figure 21: Comparison of South Island wholesale market capabilities by company

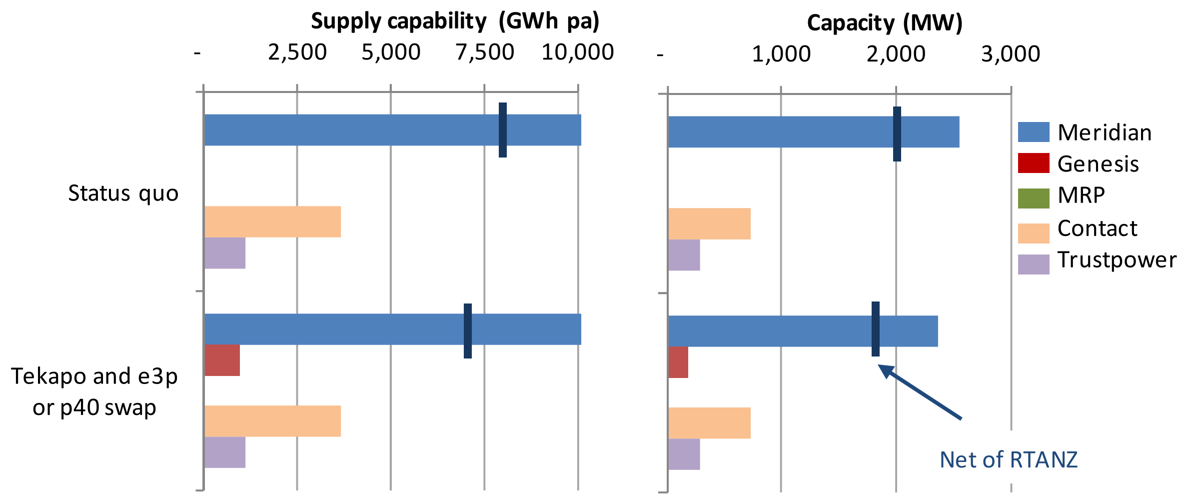
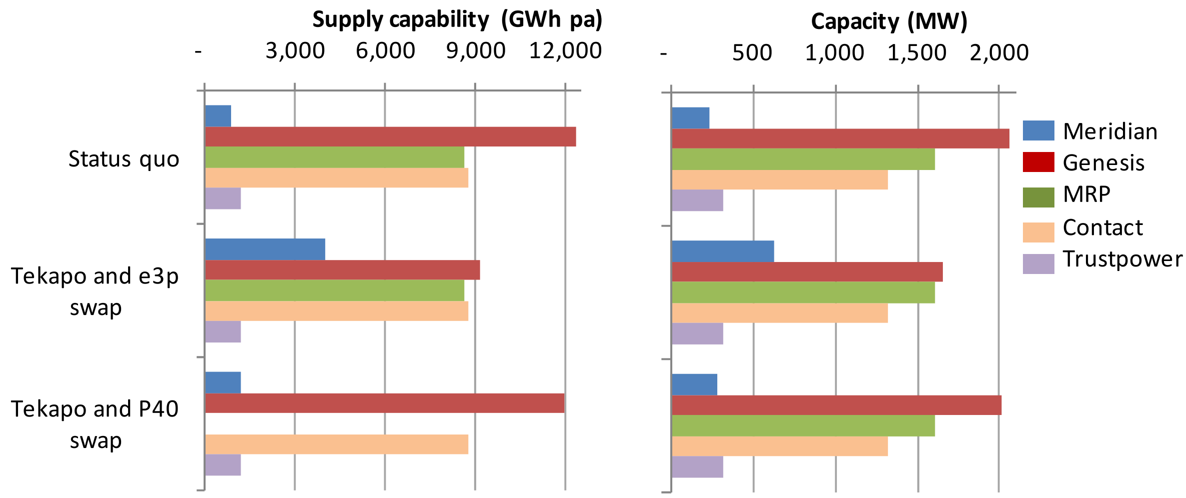


Figure 22 shows the corresponding North Island chart. The e3p/Tekapo swap would have a significant impact on Meridian and Genesis capabilities in the North Island.

Figure 22: Comparison of North Island wholesale market capabilities by company



Other market implications

Swapping Tekapo and e3p or p40 would alter the distribution of hydro storage and thermal capabilities among companies.

With the Tekapo assets, Genesis would on average generate roughly 1,000 GWh annually in the South Island. However, the same water would also be used by Meridian to generate roughly 2,000 GWh at its Waitaki stations. With Lake Tekapo, Genesis would thus control 780 GWh of storage capacity - two thirds of which would relate to generation at Meridian's stations. Except for spill, all Tekapo releases pass through the Tekapo stations into Lake Pukaki which represents approximately 40% of NZ storage capacity.

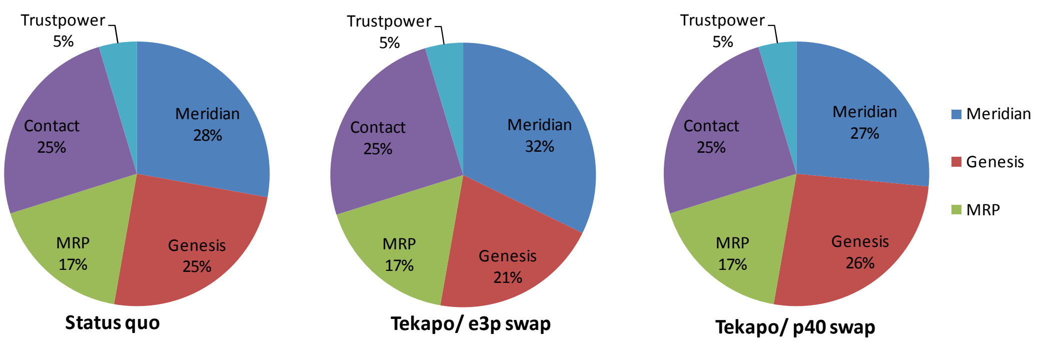
Because Lake Pukaki is a large storage lake, it largely decouples the day to day operation of the Tekapo assets from the rest of the Waitaki scheme. From a seasonal perspective though, there is a reasonably strong coupling between the operation of Lake Pukaki and Lake Tekapo storage. At present Meridian holds approximately 70% of NZ storage capacity (in the Manapouri and Waitaki systems). The asset swap would reduce this to approximately 50% and, in addition, enable another generator to indirectly influence its operation. Energy storage flexibility has significant value in the NZ market.

While transferring Tekapo assets to Genesis carries some risk of loss of medium term coordination efficiency, Genesis should be strongly incentivized to maximize generation from Tekapo (spill would bypass its stations but not necessarily Meridian's) and would introduce another view of storage into the market. Instead of internalising the management of the Tekapo scheme and the rest of the Waitaki catchment, Meridian would have to influence the operation of Tekapo storage through the impact of its offer strategy on spot prices.

Transferring Lake Tekapo may also to some extent indirectly align Meridian and Genesis perspectives regarding the management of hydro storage / thermal backup, possibly more-so if Meridian also had a substantial thermal asset like e3p. However, being the most modern CCGT, e3p would tend to operate at a relatively high load factor (also in part due to relatively inflexible gas supply) with Huntly largely filling the hydro backup role.

In that sense, while transferring e3p to Meridian would create another large thermal generator, the operation of those assets is unlikely to improve competition in the wholesale market. In fact, as shown in Figure 23, exchanging Tekapo and e3p assets would increase Meridian's overall share of the market by approximately 5% at Genesis' expense.

Figure 23: Comparison of shares of generating capabilities (GWh pa)



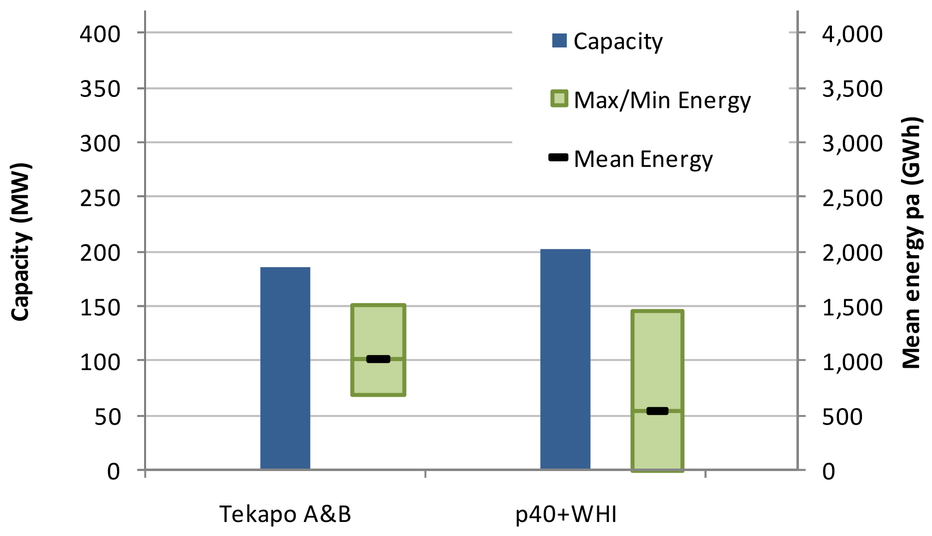
Conclusions regarding physical asset swaps

Transferring Tekapo assets to Genesis would provide a significant generation base for Genesis to develop a retail presence in the South Island, although the apparent size is potentially reduced by dry year concerns. The transfer of Tekapo assets would also reduce Meridian's dominant position in terms of hydro storage capacity. However, Meridian's South Island dominance would not be materially affected and if it owned e3p, its national supply capabilities would grow considerably.

A number of issues would need to be addressed to enable the assets to be exchanged between the companies. Although none would appear to present fundamental impediments, each would require detailed investigations to confirm feasibility and cost, especially in relation to RMA and gas supply arrangements.

Given that retail competition in the North Island is of less concern, if asset transfers were seen as desirable it may be preferable to just consider transferring Tekapo assets to Genesis. If it were also considered desirable to transfer assets to Meridian, a better balance, with less issues to resolve, would be achieved by transferring Whirinaki and possibly p40 to Meridian. The capabilities of these assets are more comparable with Tekapo assets as illustrated in Figure 24 below.

Figure 24: Comparison of Tekapo and p40 / Whirinaki capabilities.



Overall, if physical asset swaps are to be pursued, the transfer of Tekapo assets to Genesis should help to stimulate retail competition in the South Island and reduce Meridian's share of storage capacity. The benefits of other transfers would appear limited noting that retail competition in the North Island is of less concern.

Appendix 3:

Description of virtual asset swap option

The key aspects of this option are described below.

Contracting parties

Contracts would be put in place between Genesis and Meridian, and between Mighty River Power and Meridian.

Load profile in hedges

Contracts would be shaped to broadly reflect the shape of demand for a mix of residential, commercial and industrial customers. This would facilitate competition across a range of market segments. The following analysis uses the load shape for South Island demand (excluding the Tiwai smelter) as the template for allocating annual hedge volumes across seasons etc.

Hedge volumes

Hedge volumes should materially increase the island diversity of the 'supply' base for each SOE, but not be so large that they risk materially disrupting the SOEs' existing businesses. In light of these factors, a swap along the following lines is proposed:

- Meridian would sell 1,400 GWh/year of 'South Island' energy to Genesis, and buy 1,400 GWh/year of 'North Island' energy from Genesis;

- Meridian would sell 1,000 GWh/year of 'South Island' energy to Mighty River Power, and buy 1,000/year of 'North Island' energy from Mighty River Power.

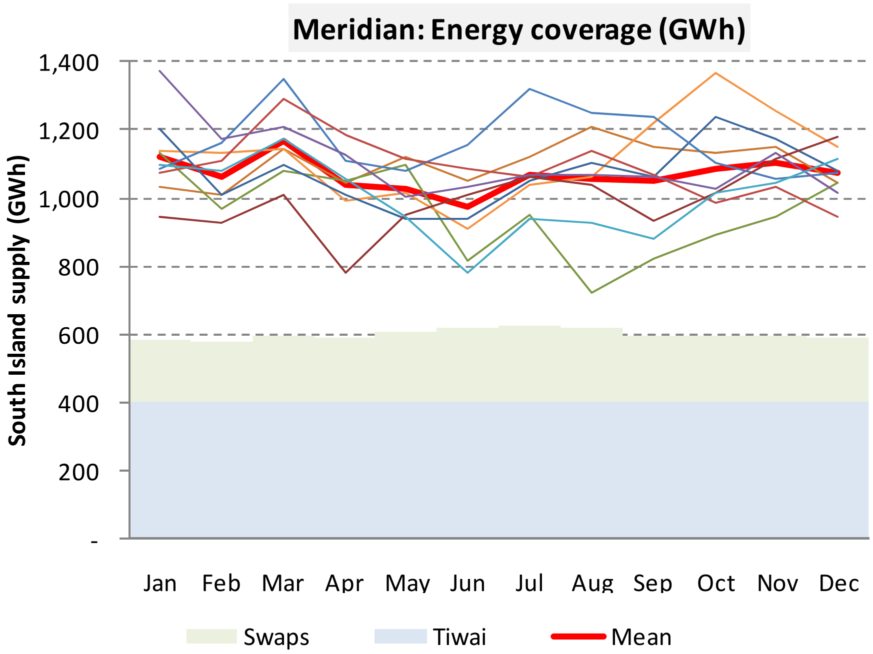
The effect of the swaps is shown in Figure 25 which depicts the energy output and capacity profiles[65] for each SOE in its home island, relative to the size of the proposed swap for that SOE. In each case, the annual swap volume has been spread across the year to reflect the load profile discussed above.

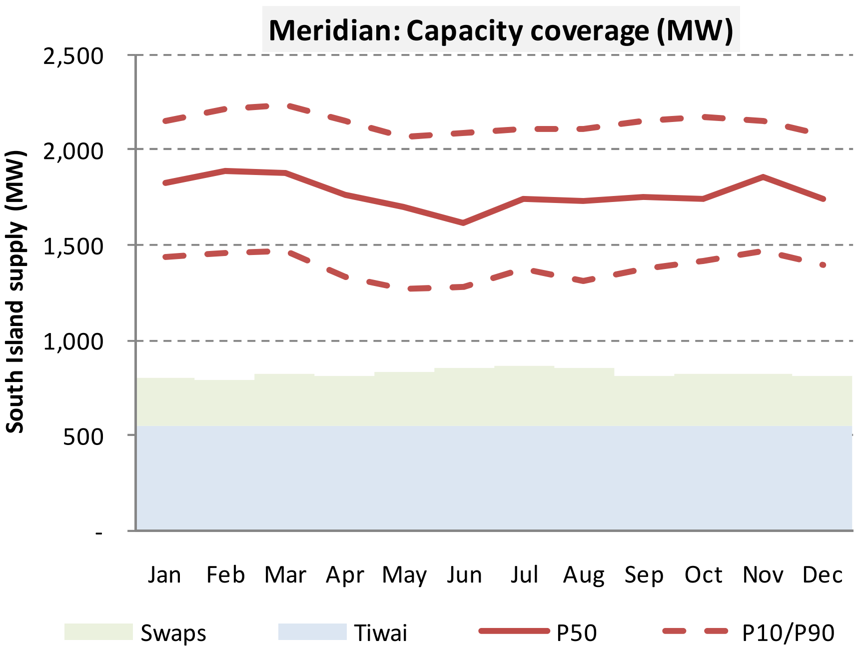
The difference between the swap level and monthly energy/capacity[66] profile indicates how much headroom would be retained by each SOE. Put another way, it shows how much hedge capability would be retained by each SOE for retail/contract sales in its home island. The amount of headroom is important because swap volumes should ensure that each SOE retains sufficient capability to remain active in its 'home island' market.

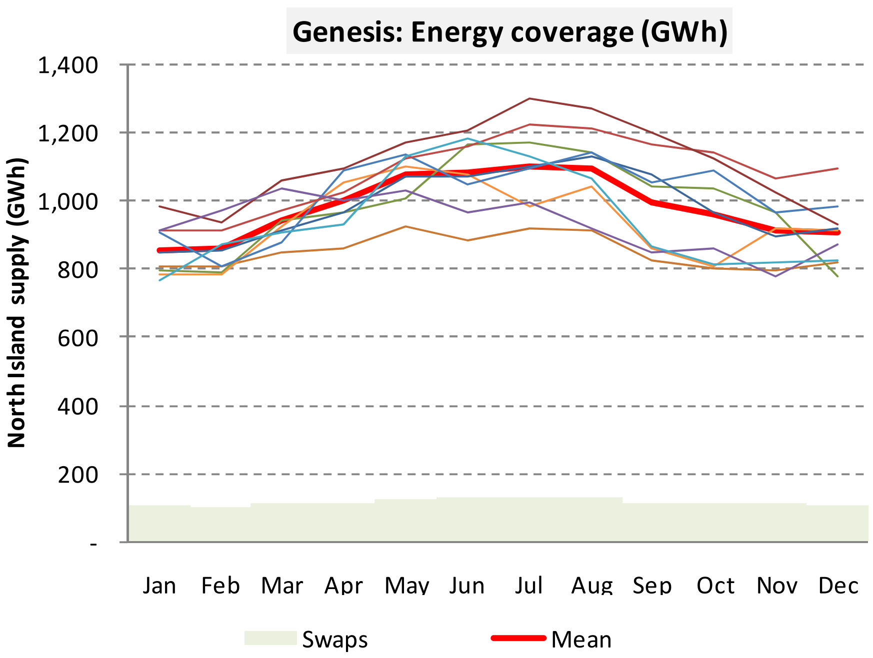
[65] These are based on observed MW output for every half hour between 2001-2008, and show the lowest 10% (P10), median (P50) and highest 10% (P90). Adjustments have been made to take account of plant built in that period (grossing up earlier years), and plant currently under development.

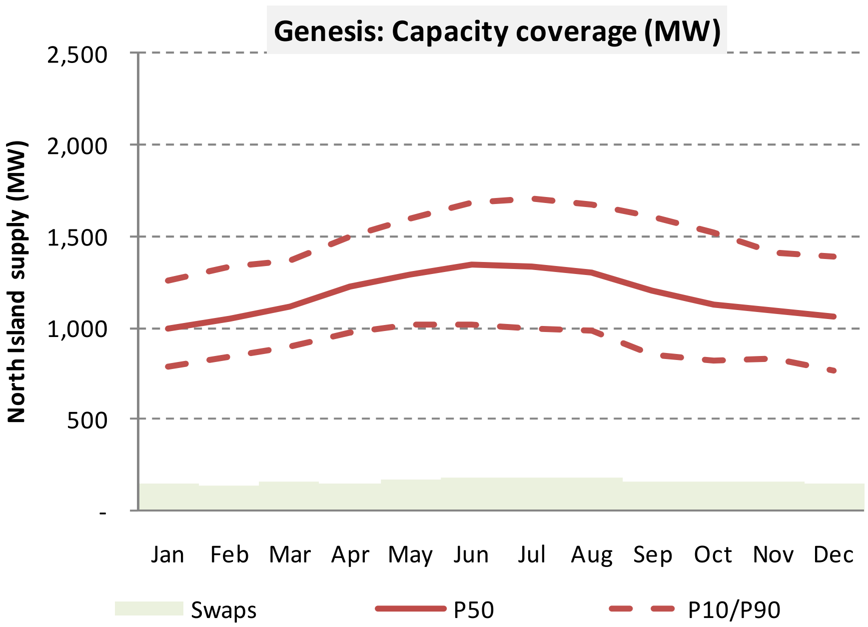
[66] These figures are based on the existing generation for each SOE, plus developments currently under construction. The monthly generation production figures represent observed output for hydro stations in the 2000-2008 period, and expected capability for other plant.

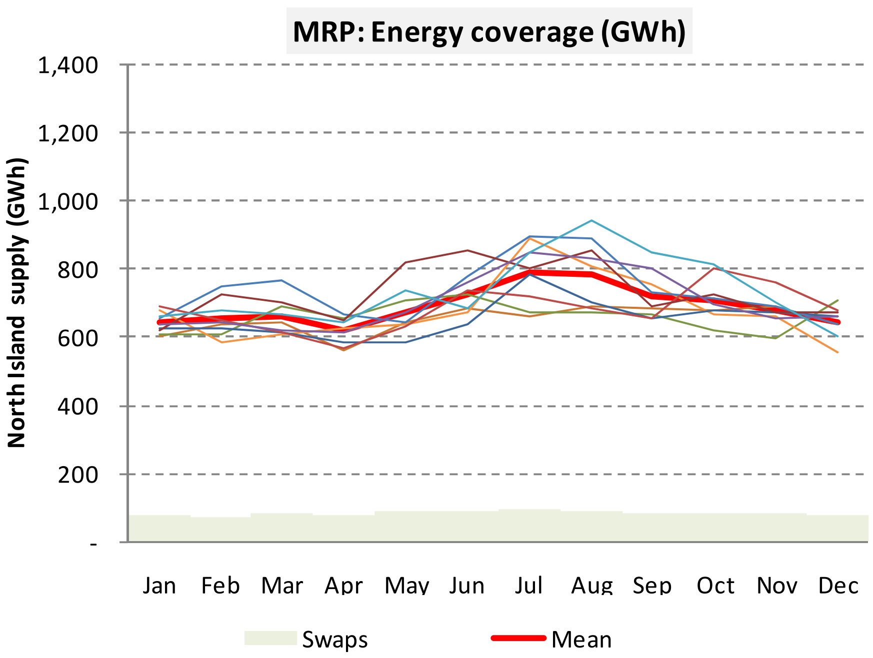
Figure 25: Estimated effect of virtual swap on 'island' hedge position for each SOE

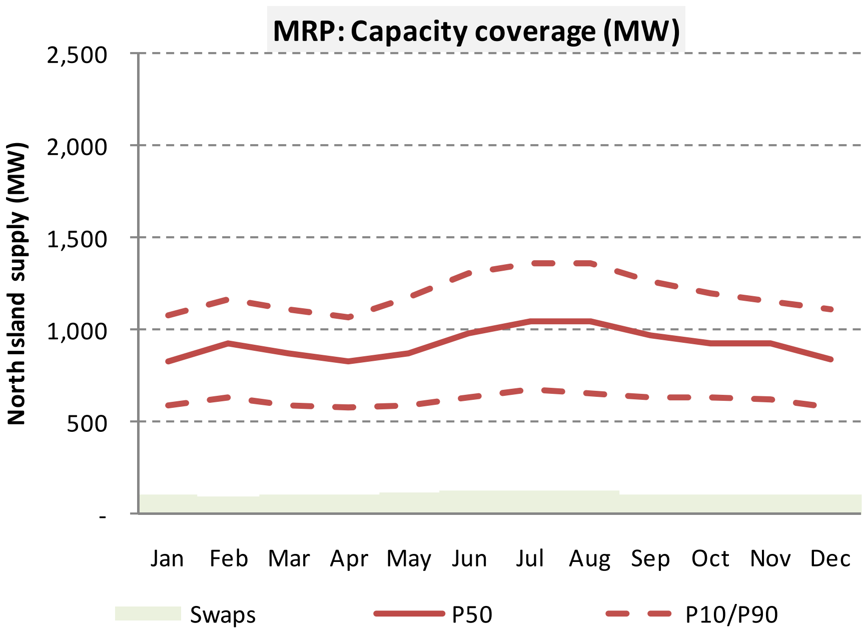





Genesis: Energy coverage (GWh)
North Island supply (GWh)
1,400
1,200
1,000
800
600
400
200
-
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Swaps
Mean


Genesis: Capacity coverage (MW)
North Island supply (MW)
2,500
2,000
1,500
1,000
500
-
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Swaps
P50
P10/P90



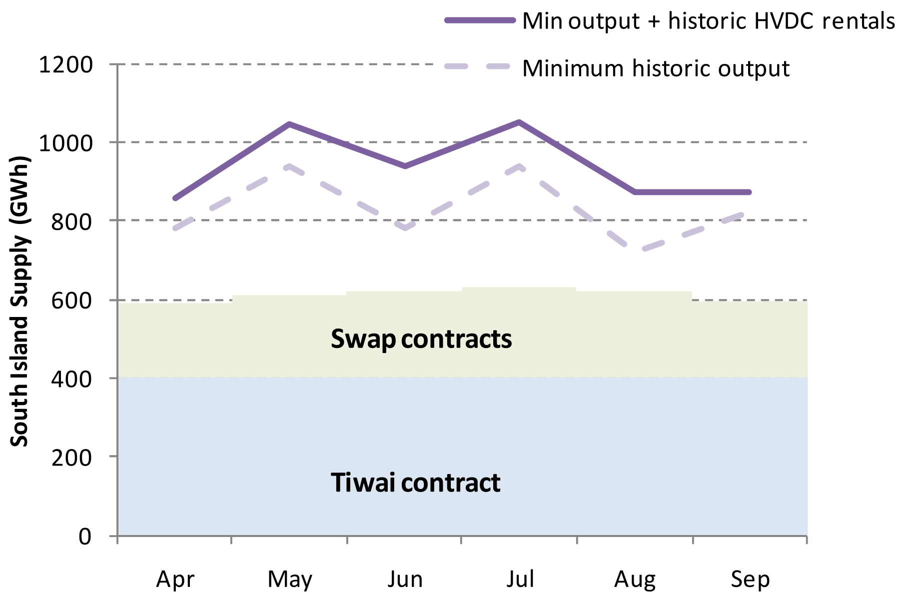


In assessing the charts, it is apparent that both Genesis and Mighty River Power should have no great difficulty in absorbing the swaps into their portfolios (especially with a ramp up phase for transition as discussed below).

By contrast, the position for Meridian is more constrained. While the energy (GWh) and capacity (MW) charts for Meridian indicate a similar picture, in practice energy is expected to be the binding constraint, as the company's large and flexible hydro base should ensure it has significant capacity to cover short term peaks in its hedge book.

As regards energy capability, despite Meridian's large average energy production (around 13,000 GWh/year), the swap volume is constrained by the need to take account of its existing term obligations to Rio Tinto[67], and the variability in production caused by hydrology. The critical period for Meridian is autumn/winter, and this is shown in more detail in Figure 26. This chart shows the monthly minimum generation profiles[66], the Tiwai hedge commitment, and the sales associated with the proposed swap.

Figure 26: Estimated energy position for Meridian in autumn / winter



The swap volume has been set at a level to provide Meridian with around 45% of its current headroom for hedge sales (excluding Tiwai), and the remaining 55% would be split between Genesis and Mighty River Power.

This should ensure that Meridian retains substantial capability to be active in the South Island retail and contracts markets. Furthermore, Meridian's level of South Island hedge capability is expected to be greater than the level shown in the chart, because it has access to a large proportion of rentals generated on the High Voltage Direct Current (HVDC) link between the islands[68].

This would mean that Meridian can use North Island generation (or NI hedge capacity which it will acquire) to partially mitigate South Island price risk. This is illustrated on the chart by the solid line, showing the volume of cover based on historic levels of HVDC transfers.

Location

Hedges would be referenced at a generation node close to where the seller has a major source of supply – for example Huntly for North Island hedges and Benmore for

[67] These assume 550MW of hedge sales, which is thought to be the level of longer term hedges (noting some of Tiwai's demand is covered by short term hedges or spot sales).

[68] This assumes that South Island generators continue to receive rentals for the HVDC, or receive the proceeds from the sale of financial transmission rights on the HVDC.

South Island hedges[69]. Buyers would bear locational price risk between these points and nodes where actual spot purchases take place. The 'within island' locational spot risk for buyers would be mitigated by the introduction of locational hedge instruments as part of the wider reform package.

Pricing

Contract prices should be set based on expected market values. Given that the volume of energy being bought and sold is the same for each SOE, the mis-pricing risk is confined to the *expected* difference in pricing across locations. This should significantly simplify the process of setting prices for these contracts[70].

The basis price difference would be settled as cash payments over the life of the hedges. For example, if North Island hedges are on average expected to be \$2.50/MWh more expensive than South Island hedges, Meridian would pay the other two SOEs a monthly amount reflecting the respective hedge volume with that party multiplied by \$2.50/MWh.

Given the uncertainties over basis risk, prices might be set out the outset for (say) 5 years, with periodic resets after that (perhaps 5 yearly). Prices should be set by negotiation, with provision for resolution by arbitration if parties cannot agree.

Duration and phasing

The contracts should have a significant term to replicate the position created by ownership of a physical asset. As a minimum, the term should be 10 years, but 15 or more is likely to be preferable. This is sufficiently long to simulate the position created by ownership, without being so long that term extends beyond the economic life of the underlying assets.

A 12-18 month phase in period should be provided to allow parties to build sales volumes to match their growing hedge positions.

Contracts could be structured in a series of declining tranches to allow for a phase out as shown in Figure 27.

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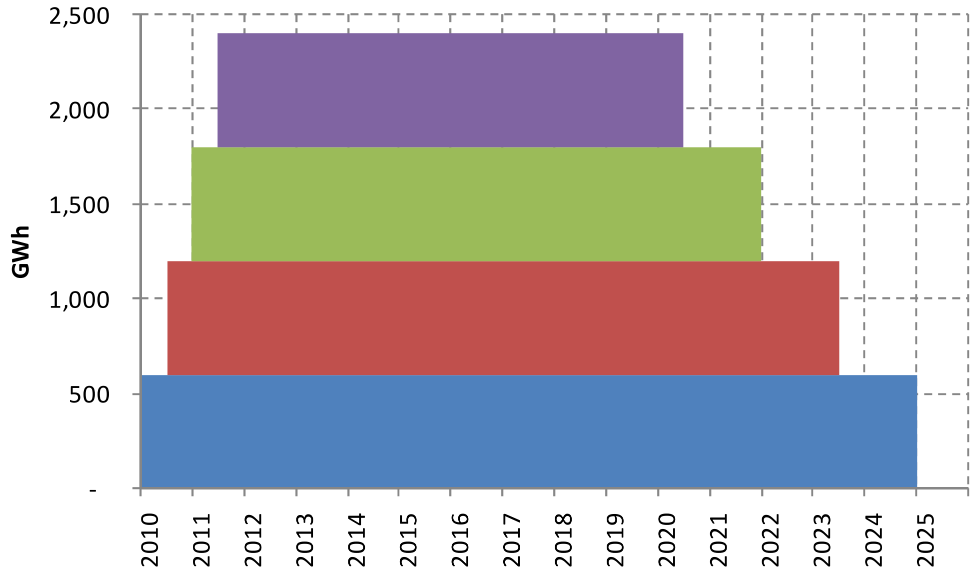
[69] More locations could be added if desired, e.g. Whakamaru.

[70] Using the oil market as an analogy, it would be the equivalent of agreeing the price *difference* payable between a barrel of oil in Singapore and a barrel at Marsden point. This is considerably easier than agreeing a long term price for oil per se. Because the proposed energy contracts are symmetrical in their buy/sale volumes, they could in fact be documented as 'basis swaps' if this were the preference of the parties.

Figure 27: Indicative contract structure



This would avoid a 'cliff face' in the contract portfolios for buyers and sellers, and facilitate the commercial negotiation of contract extensions, and/or the transition to alternatives such as new generation sources.

Credit maintenance provisions

Parties would be obliged to maintain suitable credit ratings, or post bonds or other security in the event of deterioration in their credit worthiness.

Force majeure

Sellers' obligations would only be suspended for major catastrophes that took out a high percentage of their generation capacity. This would provide strong incentives for sellers to manage supply risk, because this would be borne first by the balance of their own portfolio.

Implementation

It is possible that the SOEs would agree voluntarily to enter into such contracts particularly if the government provided mediation services. However, it is more likely that either (a) one or more of the SOEs would not consider it is in their interests to enter into the proposed contracts or (b) they would be unable to agree on terms which meet the government's objectives.

The government would therefore need the ability to direct the SOEs, which would require legislation. It would otherwise undermine the SOE model, and likely breach the SOE Act and directors' duties under the Companies Act for Ministers to seek to compel the SOE directors to agree to something they considered not to be in the best interests of their company.

One possible approach would be to provide a temporary power in legislation for the Ministers of Finance and SOEs to direct the SOEs to enter into long-term contracts, and the terms and conditions of those contracts. This would override the SOE Act and the Companies Act. The power would be similar to that in Part 8 (now repealed) of the Electricity Industry Reform Act 1998 which was used to implement the split of ECNZ in 1999.

The SOEs would be provided with a limited window (say three months) to agree on the terms and conditions of contracts, and if they failed to agree, the legislative back stop would be used.

Appendix 4:

Hedge Contracting Options

Two broad hedge contract alternatives[71] are considered in this appendix:

- Regular Mandatory Offers – this would be an ongoing requirement to offer a minimum level of hedge contracts to buyers via a pre-defined process, with a reserve price set by a mechanism independent of sellers. This option was described on page 154 of Volume 2, Appendix 20 of the Electricity Review Discussion Paper;

- Mandatory Market Maker – this is the approach recommended by Meridian. In essence, major generators (e.g. SOEs plus Contact) would have an obligation to post buy/sell prices for hedging instruments on a recognised exchange (i.e. act as 'market makers').

The following sections describe these options in more detail. This is followed by an assessment of the options in terms of expected benefits, costs and risks.

Regular Mandatory Offers

This option seeks to improve hedge market liquidity by requiring the major generators to regularly offer a minimum proportion (say 25%) of their hedge capability to buyers, including competitors, on neutral terms. This should make it easier for existing retailers to expand coverage, and for new players to enter the retail market.

Design Issues

Specifying the Sellers

Determining which generators will be obliged to make mandatory hedge contract offers is a key issue. Restricting it to SOEs would avoid suggestions that the government was unduly interfering with private property rights, but may impose an unfair burden on SOEs relative to other generator participants.

It would mean that independent retailers and electricity line businesses could largely source hedge products from the SOE generator/retailers, while privately owned generator/retailers would be free to pursue retail consumers with the backing of a full generation portfolio.

For these reasons, it is envisaged that the mechanism would apply to all generators with some form of *de minimus* exemption (say 200MW) to reduce compliance costs. At present, this would limit coverage to the five largest participants.

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[71] Virtual asset swaps can also be characterised as hedge contracting options. However, they have been considered in an earlier section and are not dealt with further in this Appendix

To reduce the adverse impact on incentives to invest in new generating plant (see later section on key costs/risks), some form of exemption would be applied to new plant built by generators that are covered by the obligation. This exemption would provide a 'holiday' for new plant of say 5-10 years before it is included in the base for calculating offering obligations.

While the mandatory offering obligation would only apply to larger generators, other sellers of hedge contracts could opt into the arrangement. For example, new entrant or smaller generators might find it attractive to participate in the process. A retailer or user that was over hedged might also use the process to sell 'surplus' hedge capacity. Such parties should be able to participate provided they meet the minimum prudential requirements for sellers.

Specifying the Sellers' Obligation

The obligation would be specified as a minimum proportion of output that must be offered by each affected generator. To keep the scheme simple, the requirement for each generator would be defined by reference to its rolling five year average level of output. Where a station is decommissioned, this would be subtracted from the relevant generators' obligation. Although this approach ignores differences in generators' underlying plant portfolios (e.g. between storable hydro and uncontrollable wind), this should not create undue problems provided the obligation is not set at too high a level and only applies to the larger portfolio generators. Subject to more detailed analysis, specifying the obligation as (say) 25% of five year rolling annual average output should be workable.

The offering requirement could be specified by reference to a generator's *gross* capability or its *net* capability after taking account of existing fixed price sale obligations. For example, should an obligation on Meridian be calculated before or after taking account of the Rio Tinto contract? The net approach better reflects the 'headroom' available to a generator for sales of new contracts. However, depending on the specific arrangements, it may create opportunities for generators to undermine the policy intent of the offering requirement. To address this, it is proposed that a net measurement basis be adopted, with contracts of greater than five years duration being netted off firm capability.

Given that demand varies over time, it would be desirable to ensure that buyers can obtain contracts with profiles that match demand. This could be achieved by sculpting the hedge contract profiles being offered, or dividing them into shorter blocks to allow buyers to aggregate profiles that suit their needs. The former approach is simpler, but is relatively inflexible as the 'standard profile' will suit some buyers better than others (e.g. retailer want more in winter, whereas industrial users tend to prefer flatter profiles).

Even though it adds a modest level of complexity, the latter approach is preferable. It was used in the mandated hedge contract offering made available by ECNZ in 1996[72]. In that process buyers could bid for hedge contracts that were broken into the fundamental building blocks of summer/winter periods, week days/weekends, and

[72] As part of the restructuring package that established Contact Energy as a separate SOE from ECNZ.

day/night periods. Buyers could bid for these blocks to assemble hedge positions that reflected their needs.

Contract Design

Contracts could be written as physical supply obligations, or financial contracts which insulate parties against spot price movements. Experience in other markets indicates that financial contracts will be preferable because they can be more easily standardised and increase the pool of potential buyers/sellers.

Hedge contracts for electricity in New Zealand have several components. At present, the most significant components are typically negotiated between the counterparties rather than being standardised. These components include details such as contract type (e.g. a two-way hedge or cap structure), price, volume, location and *force majeure* conditions.

The other design features that would need to be considered include:

- Contract type – to minimise complexity, contracts would be standard two way hedges (also known as swaps). Other contract types (e.g. caps) are possible. However, the added complexity is unlikely to outweigh the benefits;

- Location – Ideally the mandatory hedge offers would be made at the main trading points of Benmore, Haywards and/or Otahuhu rather than a multitude of Grid Injection Points (GIPs). This would aid liquidity in the contracts trading market, and provide for greater price visibility at the three main trading nodes. That said, use of these nodes would expose sellers to some locational price risk. It would be important to assess whether this risk is reasonable in light of the chosen approach to locational hedging mechanism(s); and

- Force majeure terms – Sellers' obligations would only be suspended for major catastrophes that took out a high percentage of their generation capacity. This would provide strong incentives for sellers to manage supply risk, because this would be borne first by the balance of their portfolio.

A range of other more generic components need to be specified (e.g. tax treatment, dispute resolution provisions etc) and this 'fine print' could be based on a master agreement, such as the International Swaps and Derivatives Association (ISDA) suite of contracts currently in use for contracts traded on EnergyHedge[73].

[73] EnergyHedge is the trading platform used by Contact, Genesis, Meridian, Mighty River Power and Trustpower.

Specifying the Bidders

In order to purchase hedge contracts available through the mandatory hedge contract offer, buyers would need to satisfy certain minimum prudential requirements. The prudential requirements associated with the EnergyHedge trading arrangements may provide a useful starting point, although it is noted that only the five main generator/retailers have so far participated in EnergyHedge.

The object should be to allow major users, independent retailers, and electricity line businesses to participate, without incurring unreasonable costs. To the extent that other parties (speculators and insurance providers for example) wished to participate, that might assist liquidity in the contracts market more generally.

The design of prudential arrangements is likely to be challenging, especially if contract durations extend beyond a few months, as the arrangements would need to allow for changes in the credit worthiness of counterparties. It would also be important to ensure that seller's financial robustness is addressed in the design of arrangements.

Leaving prudential issues aside, there may be merit in restricting the field of buyers for other reasons. In particular, allowing generators to bid for their own contracts may allow them to artificially support prices and potentially buy back their own hedge contracts – thus defeating the object of the mandatory offer. On the other hand, it seems desirable that the SOE generator/retailers (for example) should be able to participate in bidding for hedge contracts in regions where they do not currently have a sizeable generation base.

Possible arrangements to address this issue include:

- Precluding generator/retailers from bidding for hedge contracts at locations where they have offered hedge contracts to meet their mandatory offer requirement (while allowing generator/retailers to choose whether to meet their offer requirements, e.g. at either Benmore, Haywards or Otahuhu);

- Applying restrictions on a company specific basis, taking account of their respective asset bases.

Hedge Contract Durations

Parties wishing to develop a retail presence are likely to seek contract durations of 1-5 years to reflect to medium term nature of their sales books. This could be met by offering a withering profile of contracts, with (say) the full 25% obligation offered for 12 months ahead, 20% for 2 years ahead, etc. This type of profile would help to avoid 'cliff faces' for buyers or sellers in their contract positions. Contracts with start dates beyond 2-3 years would (in theory at least) allow new entrant generators to compete more readily.

At the outset, it could be useful to consider a phase-in mechanism as it is likely to require some time for parties to become familiar with the auction mechanism and associated market opportunities. This might extend across the first 1-2 years of the arrangement.

Auction/tender mechanism and frequency of mandatory offerings

Theory suggests that an open, multiple round auction is likely to be preferable to a closed tender mechanism, as the auction process itself will reveal information that is of value to bidders[74]. It would also allow bidders to more easily build packages of contracts that suit their requirements, because they can acquire contracts in later rounds if they are initially unsuccessful.

The key concern with an open auction is the possibility that bidders will find it easier to establish and enforce collusive arrangements. This issue should be able to be addressed via design of mechanisms to reduce the scope for collusion, such as not disclosing the identities of successful bidders until the entire auction is complete[75].

The direct cost of operating the mechanism will rise as the auction/tender frequency and complexity increases. On the other hand, the mechanism is likely to produce more robust outcomes if participants have regular opportunities to purchase contracts. This suggests a frequency of quarterly or six monthly auctions.

Reserve prices

A key issue to consider is whether to provide for reserve prices, and if so, who should set the price. The main argument against a reserve price is that the auction mechanism itself should discover the true value of each contract. While this is reasonable in principle, the limited size and depth of the New Zealand market suggests that 'rogue' outcomes cannot be ruled out, particularly if there is collusion among buyers. To address this risk, a reasonable seller might forego the opportunity to contract at times, and prefer to wait. For this reason, some form of reserve price mechanism would appear to be reasonable to reduce sellers' exposure to downside risk. However, to ensure that sellers could not use the reserve price mechanism to defeat the policy intent, the reserve prices should be set by a regulatory body. This price should reflect a reasonable minimum price – taking account of factors such as the point at which sellers could experience financial distress etc.

Assuming the contracts were broken into the main load blocks discussed above (summer/winter etc), separate reserve prices would be required for each of the main blocks. Some adjustment might also be required to take account of locational differences.

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[74] An open auction provides the bidders with information through the process of bidding. This information may stimulate competition by creating a reliable process of price discovery, by reducing the winner's curse, and by allowing efficient aggregations of items.

[75] In a multiple round auction this would mean that successful bidders are advised of *their* acceptances in each round. The only information revealed more generally would be clearing prices and sales volumes. Information on successful parties would only be released more widely when all rounds have taken place.

Implementation

Legislation would be necessary to implement regular mandatory offers as parties cannot be relied upon to adopt this mechanism and adhere to it on a voluntary basis. The legislation would need to provide for effective penalties to ensure compliance with the arrangements.

The mechanism will also need to clearly appoint an agency as the party responsible for running the auction process (it should not be left to individual companies). Under the proposed governance arrangements, this would most likely be the Electricity Markets Authority, or a party appointed under its rules.

Comment

The main concern with the rolling auction mechanism is the potential adverse impact on incentives to invest in new generation. This risk arises because generators are likely to be concerned about the reserve price being set by a party other than themselves. This concern is likely to be higher at the outset of the scheme when there will be greater uncertainty over outcomes.

The concern would be ameliorated by providing a lengthy ‘holiday’ for new generation, but unless this holiday is permanent, a dulling of investment incentives is still possible. Furthermore, because the mechanism is relatively intrusive, market participants may perceive an increased risk of future adverse changes, further undermining incentives (e.g. pressure to depress the level of reserve prices).

The other issue to consider is the possibility of generators re-trading contracts among themselves (including through derivatives) to ‘reassemble’ their original positions. While perfect ‘reassembly’ would be difficult to achieve, parties may be able to partially unwind the effect of the auction mechanism through secondary trading. This would undermine the policy effectiveness of the mechanism. Although re-trading with this sole purpose is undesirable, it would not be possible to distinguish this sort of action from other hedge trading activity. Re-trading is therefore an inherent risk with this mechanism.

Mandatory Market Maker

In its submission, Meridian sets out a proposal “to require compulsory trading in some form of New Zealand electricity futures [contracts]”. It believes this would improve hedge market liquidity, and therefore strengthen retail competition. (A ‘primer’ on electricity futures is included at the end of this Appendix).

Meridian’s model appears to have the following key features[76]:

- there would be an obligation on large generators (say >500MW installed capacity) to act as market makers. These parties would have an obligation to post buy and

[76] Meridian’s submission notes there are a range of sub-options. The description therefore focuses on what appear to the central distinguishing features of the Meridian proposal.

sell prices for predefined hedging instruments, and the buy/sell spread could not exceed 10%;

- the hedging instruments would be in the form of futures contracts;
- market makers must post buy/sell prices for quarterly contracts of 1MW volume. Prices must be posted for at least the next 3 calendar years;
- If a contract is bought or sold, the market maker must refresh its offer no later than the next trading day;
- other parties (e.g. new entrant generators, retailers) would be able to trade on the exchange (subject to prudential requirements), but would not face any obligation to act as market makers etc unless they owned 500MW or more of generation plant.

Comment

In a directional sense, this option is similar to the regular mandatory offers, but as proposed would have less potency and force. In particular, it would rely solely on the maximum buy/sell spread to discipline pricing behaviour of sellers. This may be viewed as acceptable where there is sufficient competitive tension to ensure that one seller cannot 'impose' a view on the market. However, wholesale market purchasers (including new entrant retailers) are likely to have concern on this front at times, especially in the South Island where competitive tension is more limited. Information asymmetries between buyers and sellers will compound this concern.

Leaving price issues aside, purchasers are also likely to be concerned about the usefulness of the mechanism as a source of hedge cover. The limitation arises because of the relatively small volume of primary hedge that will be available at any time (1MW x 4 sellers). This is reinforced by the absence of an obligation on market makers to swiftly refresh contract bids/offers that are taken up (market makers have until the next trading day). Together, these mean that the volume of primary hedge available on any day is limited to 4MW, compared to daily physical demand of around 5,000MW[77]. As a result, participants would find it difficult to use the mechanism to respond quickly to changing conditions. Another limitation is the fact that only flat profile contracts will be available, whereas many buyers seek to profile their hedge book to take account of within-quarter demand shape.

It is important to note that these features could be ameliorated to a considerable extent by altering some of the design settings, without fundamentally altering the mechanism's basic architecture. For example, an increase in the minimum quantity to be offered and/or shortening the price refreshment period could make the mechanism much more useful to buyers. Likewise, broadening the range of instruments to be traded could allow buyers to more closely tailor their purchases to actual load shapes.

[77] The underlying physical demand for hedge from buyers using the exchange will obviously be less than this. There will also be hedge that is potentially available from secondary trades (i.e. primary hedge bought in earlier periods). However, the fact remains that 4MW/day still appears very modest compared to potential demand for hedge.

On the plus side, the chief advantage of this option is that it would avoid any direct regulatory intervention in setting wholesale prices. This should considerably lower the risk of undermining investment incentives in new supply/demand response, as compared to Regular Mandatory Offers. The other advantage is that it could be introduced relatively quickly, because as noted by Meridian, there are existing platforms and processes that would provide a useful foundation (e.g. ASX futures contract, EnergyHedge).

Evaluating the relative benefits of different options

The key effects of the three approaches are summarised below.

Table 6: Expected Effects

Area	Regular Mandatory Offers	Mandatory Market Makers
Strengthen retail competition between existing players	✓	✓
Strengthen retail competition by facilitating entry of new players	✓✓	✓
Strengthen generation competition by facilitating entry of new players/expansion of smaller parties	✓	✓
Improve depth of hedge market	✓✓	✓
Improve discovery of forward price curve	✓	✓✓
Ease of implementation	✓	✓✓
Key risks/concerns	Possible chilling of new investment (due to concern over reserve price mechanism)	Level of potency

In summary, Regular Mandatory Offers has more design complexity (e.g. reserve prices, prudential requirements) and risk (e.g. further interventions, investment concerns). Moreover, while the main concern with the Mandatory Market Maker Option is its level of potency, this can be addressed by modifying some of Meridian's proposed terms – for example increasing (modestly) the volume of hedge that must be made available by market makers, shortening the refreshment time limit and improving the contract profile. These modifications should be feasible without introducing any major new concern.

'Primer' on electricity futures

An example of hedging using futures

A Retailer and a Generator, both operating in the North Island, each want to hedge their exposure to spot price three years out

Rather than negotiate a contract for differences with each other, they each decide to do so via the use of an ASX futures contract.

The Retailer ***buys*** a 10 MW baseload contract for electricity delivered at Otahuhu for the 3 months ending September 2012. When they purchase the contract in September 2009 the ***ask*** price on the ASX futures exchange for a Sep-12 Otahuhu contract is $90/MWh.

The Generator ***sells*** a similar 10 MW Sep-12 Otahuhu baseload contract. The ***bid*** price is $88/MWh.

The $90/MWh and $88/MWh are the prices that the Retailer and Generator will respectively have 'locked-in' for the quarter ending September 2012.
When they make their transaction in September 2009 they each have to pay a deposit, known as a 'margin'. This margin provides some measure of security to the exchange in the event of the Retailer or Generator defaulting.

The current ASX initial margin requirement is $5,250 per 1 MW contract. Thus, for a 10 MW contract the Retailer and Generator each deposit $52,500 into a margin account which they will need to set up with the ASX.

In three years time, the average actual Otahuhu spot price for the quarter ending September 2012 is $95/MWh. Both the Retailer and Generator buy and sell power from / to the wholesale market at the spot price which for 10 MW for 3 months at a price of $95/MWh = $2,080,500.

However, the Retailer and the Generator also 'cash settle' their futures contract:

- The Retailer sells back their contract which, because it was priced at $90/MWh, is worth ($95/MWh -$90/MWh) * 10 MW * 3 months = $109,500

- The Generator buys back their contract which, because it was priced at $88/MWh, is worth ($88/MWh - $95/MWh) * 10 MW * 3 months = - $153,300 (i.e. they have made a loss)

Both the Retailer and the Generator also receive their deposit (i.e. 'margin') back in full.

Thus the effective price that the Retailer has paid for its electricity

= (spot purchases - the profit on the futures contract) ÷ MWh purchased
= ($2,080,500 - $109,500) ÷ 21,900 MWh = $90/MWh

And the effective price that the Generator has received for its electricity

= (spot sales – the loss on the futures contract) ÷ MWh sold

= ($2,080,500 - $153,500) ÷ 21,900 MWh = $88/MWh

Conversely, if actual spot prices had out-turned to be $80/MWh, the Retailer would have made a loss on their futures contract (i.e. they would have had to pay money to the ASX), whereas the Generator would have made a profit. However, the effective price for the electricity they would have paid / received for the electricity would be unchanged – i.e. $90/MWh & $80/MWh, respectively.

A bit more on margins

In the above example, both the Retailer and Generator had to deposit an initial 'margin' of $52,500 into a margin account they will have set up with the ASX, as a means of providing some security to the ASX against either party defaulting. However, during the 3 years in the run-up to September 2012, the price of the Sep-12 contract may move significantly.

For example, if the bid & ask prices drop to $80/MWh & $82/MWh, respectively, then the Retailer who purchased a contract at an ask price of $90/MWh will be looking at a loss, whereas the Generator who sold a contract at a bid price of $88/MWh will be looking at a profit.

To cover the ASX's exposure to the Retailer's loss, the ASX may make a 'margin call' against the Retailer, asking them to top-up their margin account to a level equivalent to the scale of the loss – i.e. ($90/MWh - $82/MWh) * 10 MW * 3 months = $175,200. I.e. the ASX will have 'marked to market' the value of the contract.

Conversely, if the Sep-12 future price subsequently moves back up again, the ASX will credit the Retailer's margin account equivalent to the improvement in value of the contract.

This process of 'margining' typically happens daily.

Using futures for speculation

Unlike the hedging example where the Generator and Retailers have physical positions, a speculator may also buy or sell a futures contract.

Using the initial example, they may buy a 10 MW contract at an ask price of $90/MWh, and deposit an initial margin of $52,500.

They can 'close out' the contract at any point before September 2012 by 'offsetting' – i.e. selling a 10 MW contract at whatever the bid price happens to be at that time.

If, six months after they purchased the initial 10 MW contract at $90/MWh, they sell a 10 MW contract at $94/MWh, they will have made ($94/MWh - $90/MWh) * 10 MW * 3 months = $87,600.

Their % profit on the initial margin would thus be $87,600 / $52,500 = 167%. Conversely, if they felt the need to close out when the price had moved $4/MWh in the wrong direction, they will have lost $87,600. (i.e. they will have had to pay an additional $35,100 on top of their initial margin).

As can be seen, only having to place a relatively small initial deposit gives the speculator significant leverage in terms of being able to earn large profits, or suffer large losses.

Speculators and 'market makers'

It should be noted that having speculators operating in a futures market is beneficial for all concerned. This is because the greater 'liquidity' from having a greater number of people actively trading the contract:

- Improves the process of price discovery; and
- Reduces the 'spread' between the bid and ask prices.

In a very 'illiquid' market you can have situations where no-one may be seeking to buy or sell a contract at any moment in time. In such cases, it is very hard to discover the market price of the commodity.

To help overcome this, some exchanges will have official 'market makers' for particular commodities. These market makers are companies that always quote both a bid and an ask price for the particular commodity.

It is understood that the ASX New Zealand electricity futures contracts have market makers for both the Otahuhu and Benmore products.

Key characteristics of exchange-traded futures contracts

The contract is for a highly standardised contract (e.g. quantities, locations, time periods), in order to promote liquidity.

The exchange is the counter-party.