Proposed Waitaha Hydro Scheme: Assessment of Reasons, Financial Viability, and Alternative Locations

This report has been prepared for the Minister of Conservation under section 17S(4) of the Conservation Act 1987 to address certain matters relevant to an application dated July 2014 by Westpower Limited under Part B of the Act for concessions relating to a proposed hydro electric generation scheme on and around the Waitaha River.

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1. Executive summary

1.1 Purpose of report

The purpose of this report is:

- To advise DOC and the Minister that Westpower's application is not complete as defined by the Act for the reasons outlined in this report; and

- To provide a robust and objective assessment of:

  — Whether the reasons given by Westpower for the proposed Waitaha scheme are valid based on the evidence and relevant law for the purposes of Part 3B of the Act, in particular section 17S(2);

  — Whether the proposed scheme is likely to be financially viable; and

  — Whether the activity to be authorised could reasonably be undertaken in another location that is outside the conservation area in question, or in another conservation area or in another part of the conservation area to which the application relates, where the potential adverse effects would be significantly less.

The Minister is invited to receive this report as:

- "a report from any person on any matters raised in relation to the application" for the purposes of section 17S(4)(a); and/or

- "existing relevant information on the proposed activity" for the purposes of section 17S(4)(b).

1.2 Key conclusions

Based on the analysis in this report:

- Westpower's reasons for the proposed Waitaha scheme are not supported by the evidence or are not relevant under Part 3B of the Act. Individually or together, Westpower's reasons do not therefore provide sufficient reason to conclude that it would be appropriate in terms of section 17S(2) of the Act to authorise an activity in a conservation area that would impose adverse effects.

- The Waitaha scheme is not likely to be financially viable in the reasonably foreseeable future. It would therefore not seem to be "appropriate" in terms of 17S(2) of the Act to authorise such a business to impose adverse effects in a conservation area.

- There is a wide range of alternative locations within the relevant time-frame at which the activity in question could be reasonably undertaken outside the relevant conservation area. Under section 17U(4)(a) of the Act, the Minister is therefore not allowed to grant concessions for the activity proposed by Westpower in relation to the Waitaha scheme.

Under section 17S(2), "appropriate" is a more demanding standard than just lawful. At law, what is appropriate is strongly informed by the Act's statutory purpose, which is to "promote the preservation and protection of natural and historic resources for the purpose of maintaining their intrinsic values, providing for their appreciation and recreational enjoyment by the public, and safeguarding the options of future generations."

On the question of whether the proposed scheme may become financially viable sometime beyond the reasonably foreseeable future, the answer is: it is not possible for anyone to predict with any confidence.

- Under MBIE's draft base case scenario, the Waitaha scheme could become viable from around 2021.

- Under MBIE's high geothermal availability scenario, it would not become viable until 2024 or even 2027.

- Under First NZ Capital's wholesale price projection, it would not be economic even by 2024.

In reality, prices beyond 2020 are too uncertain to forecast with any confidence. Some of the relevant factors are outlined in section 8.5 of this report. At best, any current view of prices beyond 2020 is simply a scenario (one of many) against which changes in the market can be monitored.

What can be reasonably concluded now in relation to the Waitaha scheme's financial viability beyond 2020 is this:

- For it to become viable around 2021 would require a relatively sudden and substantial rise in wholesale prices – in the order of 30% on current prices.

- Such a substantial rise over such a short duration would seem unlikely based on current information and previous patterns of structural change in medium to longer term wholesale prices.

- There are a significant number of fully consented new generation projects that appear to have materially lower unit costs than the Waitaha scheme.

- It would not be sensible, for the New Zealand electricity system or electricity consumers on Westpower's network, for the Waitaha scheme to be built ahead of new generation options with a lower unit cost.

- As the 2009 Ministerial Review observed: "It is important to minimise the costs of new generation, get the right generation built, and ensure that alternatives such as energy efficiency are fully exploited."[1]

1.3 Structure of report

The essence of this report is its executive summary. The 13 sections that follow are like appendices. They contain the analysis and references used in establishing the key points set out below. For completeness, and for a reader's convenience in reviewing references, source material is included in some detail in the sections that follow.

Answering the three questions central to this report could have been confined to a selection of material sections 10 to 13. However, to properly evaluate those three issues, it was considered important to understand in some detail the:

- Statutory context and process;
- Nature and history of Westpower's business, including its strategy for the future;
- Proposed generation scheme;
- Electricity supply and demand in Westpower's region;
- How it relates to the wider New Zealand electricity market;
- Westpower's rationale for the scheme; and
- Alternatives to the proposed scheme.

This process of enquiry is reflected in the structure of this report. It has given rise to other relevant key issues, which are outlined below.

1.4 Approach

This report has been prepared from an independent and objective perspective. It has not been prepared to support or critique any particular party or position. The analysis and conclusions reflect the relevant available facts using standard methods of analysis in the electricity industry.

1.5 Statutory framework

1.5.1 Part 3B of Conservation Act

Westpower has applied to the Minister of Conservation for concessions to use conservation areas for the construction, operation and maintenance of a hydro-electric generation scheme on and around the Waitaha River.

[1] "Ministerial Review of Electricity Market Performance", Electricity Technical Advisory Group and the Ministry of Economic Development, August 2009, Volume 1, para 54

With certain limited exceptions, any non-recreational activity in conservation areas is prohibited unless authorised by a concession. The range of activities prohibited without authorisation is very wide and includes any trade, business, or occupation.

The regime relating to the authorisation of activities in conservation areas is set out in Part 3B of the Conservation Act 1987. It is separate and distinct from the regime for granting resource consents.

The purpose of the Act from its long title is "to promote the conservation of New Zealand's natural and historic resources". “Conservation” means “the preservation and protection of natural and historic resources for the purpose of maintaining their intrinsic values, providing for their appreciation and recreational enjoyment by the public, and safeguarding the options of future generations.”

This statutory framework is described in more detail in section 2.3 of this report.

1.5.2 “Appropriate” test

Under Part 3B of the Act, the threshold for authorising an activity in a conservation area is as follows:

- If an application for a concession is (i) complete, (ii) not required to be declined under one of the three categories, (iii) there are adequate or reasonable methods for remedying, avoiding or mitigating adverse effects, **and** (iv) there is sufficient information to assess effects, then:

- The Minister weighs the effects of the proposed activity and other relevant factors (on the one hand) against the conservation values of the relevant conservation area (on the other), making a decision that gives effect to the statutory purpose of the Conservation Act 1987.

- If the concession sought is a lease, *profit à prendre*, licence, or easement, the Minister must be satisfied it is **both** appropriate and lawful. If it is not, the Minister may not grant the concession. (Emphasis added)

Westpower is seeking concessions in the form of leases, licences and easements, and therefore the Minister must be satisfied the proposed activities are both appropriate and lawful.

“Appropriate” is a more demanding standard than just lawful. At law, what is appropriate is strongly informed by the Act’s statutory purpose, as outlined above.

The decision-making steps that the Minister is to follow under Part 3B of the Act are set out in flow diagrams in section 2.11 of this report.

1.5.3 “Activity” to be authorised

The activity to be authorised by the Minister under the Act is the “business of generating electricity” in the relevant conservation area. This is described in more detail in section 2.4 of this report. Other activities to be authorised include building, operating and maintaining the structures and facilities that would comprise the scheme, together with concessions for the structures and facilities to remain on the relevant conservation areas.

1.5.4 Legal relevance of financial viability

The required contents of any application under Part 3B are prescribed in sections 17S(1) and 17S(2) of the Act. The matters to be considered by the Minister are set out in section 17U.

Financial viability is a distinct matter to be considered by the Minister in deciding whether to grant a concession. As the Minister stated in his 2014 decision on the application by Riverstone Holdings Limited ('RHL') for a proposed monorail in Fiordland: "it is common sense to look at financial viability when I, as Minister, decide whether to give the Crown's "landowner" permission to use the public land." Strong reservations about financial viability were one of five distinct reasons given by the Minister for declining RHL's application.

If the activity in question is not financially viable, it would not be "appropriate" (and probably not lawful) in terms of 17S(2) of the Act to incur adverse effects on conservation values. To authorise a non-viable business with such effects would be inconsistent with the Act's purpose, which as outlined above is "to promote the preservation and protection of natural and historic resources for the purpose of maintaining their intrinsic values, providing for their appreciation and recreational enjoyment by the public, and safeguarding the options of future generations."

1.5.5 Legal relevance of electricity need and other reasons

Section 17S(2) requires an applicant to supply, in addition to the contents required by section 17S(1):

> "**reasons for the request** and sufficient information to satisfy the Minister, in terms of section 17U, that it is both appropriate to grant a lease, *profit à prendre*, licence, or easement and lawful to grant it" [emphasis added]

In relation to the proposed Waitaha scheme, reasons for Westpower's request obviously include why it considers the proposed power scheme is needed. Westpower gives various reasons as to why, in its view, the Waitaha scheme is needed, including to meet forecast growth in electricity demand (from 50 MW in 2012 to 70 - 80 MW by 2030) and security of supply.

The question of whether the proposed scheme is needed is examined in some detail in section 10 of this report. It is clear under the Part 3B of the Act that, if the scheme is not needed, it is unlikely to be "appropriate" in terms of section 17S(2) of the Act to incur adverse effects on conservation values.

Westpower's reasons for the proposed activity are examined in terms of section 17S(2) in section 12 of this report.

1.5.6 Alternative locations for activity

As noted above, section 17U(4)(a) requires the Minister to decline an application for concessions if he or she is satisfied the activity could reasonably be undertaken in another location outside the conservation area. Under the Act, the activity at the alternative location does not have to be undertaken by the applicant.

In this case, consideration needs to be given to a wide range of alternative locations for carrying out the overall activity in question. This is discussed in section 13 of this report.

1.5.7 Application not complete

Westpower's application is not complete in terms of section 17S of the Act. It does not contain any information on whether the proposed Waitaha scheme is financially viable, and it fails to properly outline the range of alternative locations for the activity in question.

1.5.8 Amethyst precedent

At law, the Waitaha scheme must be considered on its own merits without making any presumptions or assumptions on the basis of the Amethyst scheme, the Minister's evaluation of Westpower's Amethyst application, or the Minister's decision to grant concessions for the Amethyst scheme.

1.6 About Westpower

Westpower's business is described in section 3 of this report. Some key points are as follows:

- Until 1999, Westpower owned local hydro generation, in particular Kumara-Dillmans-Duffers, Arnold, Kaniere Forks, Mackay Creek, Wahapo, Fox Glacier and the Turnbull power schemes. Westpower was displeased at having to sell those assets.

- The business of electricity distribution tends to relatively low growth, particularly when demand for electricity is flat, as it is for Westpower on a medium term outlook. The focus in is primarily on efficiency, security and reliability – containing costs while delivering security. However, Westpower clearly wants to grow. This is evident from its history of electricity demand forecasting (reviewed in section 6 of this report), its investment in electrical engineering and electricity transmission service businesses, and its initiatives to invest in new generation projects.

- Westpower's revenues from sources other than its monopoly local lines business (and excluding related party transactions) now account for approximately 60% of its total revenues. From 2006 to 2014, total assets grew 94%, total equity increased 64%, and gearing increased from 21% to 33%.

- Westpower is clearly keen to re-build a set of electricity generation assets. Following the relaxation in 2001 and 2004 of statutory restrictions on electricity distribution businesses owning (or being involved with) electricity generation and retailing, Westpower decided to "re-enter electricity generation" on the grounds that it had considerable management expertise and experience in hydro generation. Since at least 2003, Westpower has been developing new hydro generation projects.

- Westpower now has an 88% share in Amethyst Hydro Limited, which is a joint venture company with Harihari Hydro Limited (12% share[2]) that owns the 7 MW hydro scheme on the Amethyst Ravine near Harihari commissioned in June 2013. It is important to note, however, that Westpower does not sell electricity to consumers. It simply delivers electricity from the transmission grid and local generation to consumers. The electricity is sold by competing retailers. Electricity from Westpower's Amethyst hydro scheme is reportedly sold to Trustpower under an off-take agreement.

- Westpower services a small population relying on a relatively limited range of economic activity – mainly mining, dairying and tourism. It supplies about 13,000 consumers. By number, 93.5% of Westpower's connections are small consumers. Larger consumer connections total around 25 in number and this has been reasonably steady for the last three years. There were just two electricity users in Westpower's region consuming more than 5 MW of electricity – Oceana Gold and Westland Milk Products. Only another five consume more than 1 MW. This concentration of consumption highlights Westpower's exposure to changes in electricity demand by its small number of larger customers, which has been particularly evident during the last four years with the closure of Pike River mine (2010), Spring Creek mine (2012), and Oceana Gold's open pit at Reefton by mid-2015. Westpower is also significantly exposed to international dairy prices over time.

- Westpower's network covers a large geographical area with challenging terrain and extreme weather conditions. Its electricity distribution network comprises about 2,252 kilometres of power lines covering a region from Lyell in the North to Paringa in South Westland, an area of about 18,017 square kilometres.

- For the year ended 31 March 2014, the 'maximum coincident system demand' on Westpower's network was 48 MW. This is a significant decline on its 2011 peak of 55 MW, which was followed by consecutive falls in 2012, 2013, and 2014. On average, around 8.5% to 13% of electricity is lost in transporting electricity to Westpower's network using Benmore as the reference point.

- Westpower is one of the smallest electricity distribution businesses in New Zealand. Combined with Buller Electricity, it represents around 0.6% of total electricity connections in New Zealand, 0.9% of total energy delivered in New Zealand, and 1.4% of total system length in New Zealand. Because it is small and owned by a consumer trust, Westpower is not subject to price-quality regulation like other electricity distribution businesses, only information disclosure.

More information about Westpower's business is set out in section 3 of this report.

1.7 Waitaha scheme

The proposed scheme is described briefly in section 4 of this report. In essence, it would take and divert up to 23 cumecs of water leaving a residual 3.5 cumecs to flow into Morgan Gorge. The water would be diverted by a weir and diversion structure at the bottom of Kiwi Flat, flow

[2] This 12% share is held 50/50 by Martin Christopher Doyle and Robert Allan Smith – http://www.business.govt.nz/companies/app/ui/pages/companies/1539938/detail

into an intake structure, down a 1.5 kilometre tunnel, through penstocks, into a powerhouse located below the Morgan Gorge, and then, via a tail-race structure, back into the natural flow of the Waitaha river. It would be a run-of-river scheme with no ability to store water. The scheme is intended to produce 110 – 120 GWh per year with a peak output of 16 – 20 MW.

The proposed scheme is primarily located, within stewardship conservation land managed by the Department of Conservation. A small area of the scheme is located within private land, immediately north of the stewardship land.

The Upper Waitaha Catchment, within which the proposed scheme would be located, is an area of outstanding natural values. The local adverse effects of the proposed scheme on natural character, landscape, visual amenity and recreational (kayaking) values have been assessed as high.

Westpower would not sell the electricity produced by the Waitaha to consumers. Rather, it would be sold into the wholesale electricity market and/or to one or more electricity retailers (such as Trustpower, which owns and operates several small hydro schemes on the West Coast).

Westpower states that "there would only be short periods at low load when there may be power exported from the region and it is not expected to be significant".[3] However, Westpower's forecasts indicate that the addition of the Amethyst scheme is expected to cause the equivalent of around 55% of its output to be exported out of the region. It is not clear what proportion of the Waitaha's output would be exported rather than used to reduce volumes from the grid.

More information on the proposed Waitaha scheme is set out in section 4 of this report.

1.8 Test of financial viability

"Firms should only invest in additional generation plant when the wholesale electricity price and frequency of supply scarcity generates sufficient operating surplus to justify new generation plant."[4] The question in this case is, therefore, whether relevant wholesale electricity prices and frequency of scarcity would generate sufficient operating surplus to justify the Waitaha scheme. If not, it is not financially viable.

When the data is not available to carry out a detailed discounted cashflow (DCF) analysis, the orthodox methodology for assessing whether a new generation project is likely to be financially viable is to measure whether wholesale prices likely to be received over the medium to longer term for electricity sold from the proposed scheme are, on average, above or below the full cost of producing it – if below, the proposed scheme is negative in net present value terms, which means it is neither an efficient choice of new generation nor financially viable.

The full cost of electricity from a generation scheme includes not just operating costs, but also capital costs. This is called the 'unit cost'. It is the wholesale electricity price a generator needs

[3] Westpower's Answer to Q21 - http://www.westpower.co.nz/news/article/questions-and-answers-waitaha-hydro

[4] Test for investment in new generation set out in "A Critique of Wolak's Evaluation of the NZ Electricity Market: Introduction and Overview" by Prof Lewis Evans, Seamus Hogan and Peter Jackson, Working Paper No. 08/2011 at pages 9-10

to earn, on average, in order to recover capital and operating costs and earn an economic return on investment.

Some interested parties tend to over-look or under-value the cost of capital. In hydro generation, operating costs are relatively very low, but the cost of capital is relatively high. It is driven by relatively high construction costs. It also needs to include an appropriate risk-adjusted return on equity, as well as debt.

More information on financial the test of financial viability and how the New Zealand market prices electricity in the wholesale market is set out in section 5 of this report.

1.9 Supply and demand in Westpower's region – 2001 to 2014

The Amethyst and Waitaha hydro proposals emerged during a period of relative economic boom on the West Coast – 2001 to 2010. Forecasts of electricity demand growth in that period became almost frenzied. This reached its peak in 2010 when Westpower forecast electricity demand of 97.6% over 10 years.

Several new generation schemes were proposed during those 10 years offering significantly more additional capacity than was required. Expectations became feverish, with The Press reporting in 2009 that:

> "The West Coast Regional Council is investigating how the region could harness its hydro potential and become a powerhouse. There are six hydro schemes consented or proposed for the Coast, with the potential to produce 200 megawatts and make the region a net exporter of electricity. Regional council chief executive Chris Ingle this week presented a report to the council recommending it look into how it could encourage hydro projects. The report said electricity demand on the Coast was expected to double in the next 10 years to 110MW. It could be more than 200MW by 2040."

The perception was that:

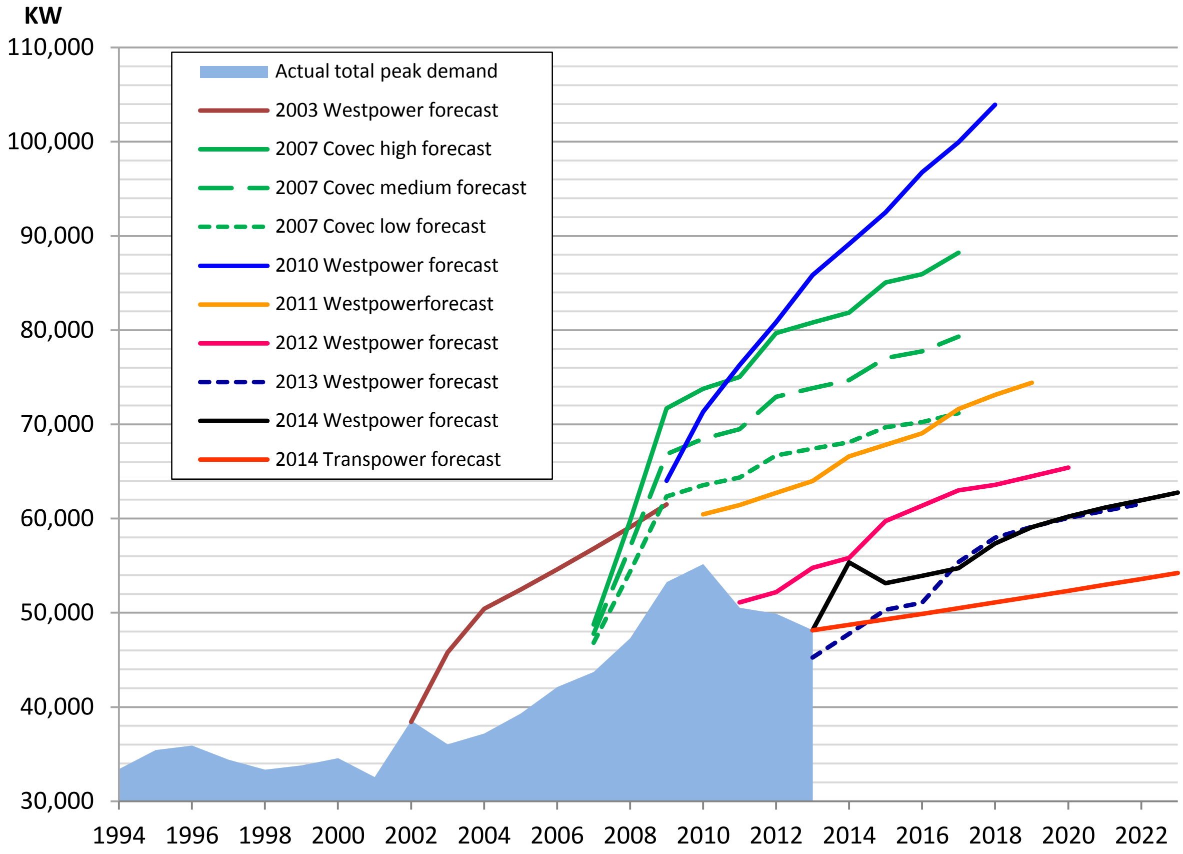
> "the Coast has been leading the country in economic development, thanks to its dairy, mining and tourism industries, but it's always been **held back** to some extent by having to import...power from elsewhere".[5] [Emphasis added]

This view that the Coast is held back by not being self-sufficient in electricity is still a key plank of Westpower's rationale for the Waitaha scheme in its application to the Minister of July 2014.

However, electricity demand on Westpower's network decline sharply from 2010. Despite successive decreases, Westpower continued to forecast relatively strong growth. As can be seen in the chart below, except for Transpower's 2014 forecast, all of the growth forecasts since 2003 at least have been consistently over-optimistic, some rather wildly so. In short, the rate of

[5] Article in "Energy NZ" Vol.4, No. 4, July-Aug 2010 – "West Coast hydro renaissance" - http://www.contrafedpublishing.co.nz/Energy+NZ/Vol.4+No.4+July-August+2010/West+Coast+hydro+renaissance.html. See also the article in New Zealand Energy and Environment Business Alert – December 22nd, 2007http://nzenergy-environment.co.nz/home/free-articles/west-coast-electricity-demand-set-to-skyrocket-as-economy-booms.html#sthash.y2C5cfoF.dpuf

growth has been massively over-estimated and the rate of decline has been significantly under-estimated.



The growth in electricity demand from 2001 to 2010 came mainly from a small number of large customers: Westland Dairy, Pike River mine, Solid Energy, Oceana Gold, a couple of other small mining operations, and associated industrial and commercial activity.

The key causes of the decline over the last four years have included the Pike River mine disaster in November 2010, Solid Energy's 2012 decision to suspend all the work at its Spring Creek mine, and Oceana Gold's announcement in June 2013 that its open pit at Reefton, which was commissioned in 2007, is to be mothballed by mid-2015 due to declining gold prices. In the neighbouring network of Buller Electricity, Holcim announced in June 2014 that it would be closing its cement factory at Westport in the second half of 2016.

When the decline started toward the end of 2010, Transpower and Westpower had started work on projects to significantly increase electricity supply capacity for Westpower's network. Based on an approval obtained in 2008, Transpower completed a significant upgrade of transmission services into the West Coast, effectively doubling supply capacity.

In 2009/10, Westpower started construction work on its Amethyst hydro scheme, which was commissioned in mid 2013. Westpower's Information Disclosure would suggest that a significant proportion of the Amethyst's output is expected to be exported outside the region.

As shown in the table below, the Amethyst and Waitaha schemes were developed along a similar time-frame.

	Amethyst scheme	**Waitaha scheme**
2003	Environmental impact assessment report	
2004	Westpower says it was invited to join Amethyst project in 2004	Westpower undertook a survey of various rivers
2005		Scoping study by S Matheson. Civil pre-feasibility study by Matheson and McCahon. Pre-feasibility environment risk assessment.
2006	Final feasibility and design. Application to Commerce Commission	Hydrological monitoring
2007		Westpower announces intention to proceed
2008	Minister grants concessions	
2009		Put on hold to focus on the construction of Amethyst scheme
2010	Tunnel construction underway	
2011	Transpower's major West Coast transmission upgrade commissioned. West Coast demand declines significantly (YE 31 March 2011 – 14)	
2012		Westpower announces intention to proceed. Consultant reports
2013	Amethyst scheme commissioned	Consultant reports
2014		Westpower applies to Minister/DOC for concessions

With the decline in electricity demand on the West Coast since 2010 combined with the transmission upgrade in 2011, supply capacity for Westpower's region became significantly greater than demand. As outlined below, the rest of New Zealand also came into a surplus of supply relative to demand, and wholesale electricity prices became flat.

As a result, and consistent with rational economic decision-making, most of the other West Coast new generation projects under development between 2003 and 2012 have been cancelled or deferred indefinitely. That these projects are not proceeding is not surprising. While the Stockton options are tied up with Solid Energy's future, the change in supply and demand conditions since around 2010 has been key issue in the future of all new generation options. These decisions not to proceed are consistent with the approach of other key electricity companies around New Zealand.

More information on electricity supply and demand on Westpower's network from 2001 to 2014 is set out in section 6 of this report.

1.9 Supply and demand in New Zealand – 2001 to 2014

In the wider context, electricity demand in New Zealand also grew strongly between 1990 and 2010. However, it too has decline significantly since 2010. National consumption at December 2014 has not increased relative to national consumption at December 2009.[6] Most of the drop in demand has come from industrial sectors such as wood, paper manufacturing, chemicals and basic metals. Household residential demand has also fallen. As New Zealand's population has continued to grow over recent years, New Zealand's residential electricity use per capita has fallen.

On the supply side in New Zealand, a large amount of new generation capacity (about 2,207 MW) was built between 2001 and 2014 – equal to about 27%% of total capacity in 2001. Of the new capacity added, around 25% of it is base load geothermal capacity, 44% thermal and 27% wind. In the same 14 year period of 2001 to 2014, some less efficient thermal generation was retired or decommissioned. The result has been a net increase in New Zealand's generation capacity of about 16%.

The national transmission grid was also substantial upgraded, including increasing the HVDC capacity to 1,200MW, which means, among other things, that electricity can flow relatively freely between the North and South Islands in both directions, transporting electricity from its generation source to where it may be needed.

The result is a significant surplus of supply relative to demand. As stated in the 2014 report of the Security and Reliability Council:

> "Assessed against the security standards set by the Electricity Authority, the New Zealand electricity system is currently oversupplied in generation following recent generation investment. This was likely in part due to recent low demand growth".[7]

Reflecting this capacity surplus and weak demand growth, the trend in wholesale electricity prices over the last few years has been flat, even declining somewhat in real terms. The average of wholesale prices since January 2012 has been about $75/MWh.

Responding in a commercially disciplined manner to these supply and demand conditions, electricity companies and developers have, since around 2012, terminated or deferred indefinitely a significant number new generation projects that were announced during the earlier boom period. As Transpower notes in its 2014 Annual Planning Report, there were no committed new grid connected generation projects.

More information on electricity supply and demand in New Zealand from 2001 to 2014 is set out in section 7 of this report.

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[6] New Zealand Energy Quarterly, December 2014 Quarter, released by MBIE on 26 March 2015

[7] Security and Reliability Council, "The system operator's annual assessment of security of supply", 28 May 2014, at bottom of page 6

1.10 Supply and demand outlook for New Zealand

The outlook for growth in electricity demand in New Zealand remains relatively weak. The Ministry of Business, Innovation and Employment ('MBIE') has recently released its latest Draft Electricity Demand and Generation Scenarios, which is dated 2 April 2015. Under its draft base case, electricity demand grows at 1.1% per annum compared with GDP growth of 2.0%. Most GDP growth comes from the less energy intensive commercial sector. This outlook is relatively unchanged since MBIE's outlook as at 2012, which also projected a base-case scenario of growth at just 1.1% per year

In terms of fundamentals, the supply situation is still adjusting to the large increase in geothermal generation over recent years and the decline in demand. Some reduction in thermal generation is likely to be required. It would appear that Contact Energy is making adjustments to reduce its thermal fuel commitments, as reflected in Contact Energy's latest Maui gas contract.

In its Investor Day presentation of 30 April 2015, Meridian Energy observed that demand in the last 12 months was 2.1% higher than the preceding 12 months; however Meridian is still expecting growth to be lower than seen historically, which has clear implications for new generation.

The medium term outlook is exacerbated by the uncertainty relating to the future of the Tiwai aluminium smelter, which consumes about 13% of New Zealand's total electricity supply. Whether the smelter continues to operate (and, if so, at what level) has yet to be decided. There is a strong view that it is likely to reduce the volume of electricity it purchases from Meridian by 172MW. Whether Tiwai buys that 172MW from another generator, or simply reduces the smelter's consumption to 400MW, is not clear at this stage. However, if the smelter were to close, a reduction in wholesale prices, or an equivalent reduction in generation capacity, is likely to be more significantly greater. Modelling MBIE indicates that electricity demand would require 9 years to recover if Tiwai closed.

The outlook for wholesale electricity prices indicates that there is no need to build new capacity in the medium term. Current projections of medium to longer wholesale electricity prices are outlined below (in the context of commenting on whether the proposed Waitaha scheme is likely to be economic (or financially viable)).

More information on the outlook for electricity supply and demand in New Zealand is set out in section 8 of this report.

1.11 New generation options for New Zealand

As noted above, a large volume of new generation capacity is waiting to be built with consents already obtained. In April 2015, MBIE advised that there is over 4700 MW of generation that has been consented. The majority of consented generation is wind (over 3000 MW). There is an additional 714 MW of consented renewable generation, including 263 MW of geothermal. There is also 980 MW of consented gas. In addition to new generation proposals already consented, a large number of options have been scoped for which consents have yet to be sought.

The relative long run cost of these new generation options is modelled by MBIE in its generation cost model. This feeds into MBIE's Electricity Demand and Generation Scenarios for New Zealand (EDGS). In general, it only models grid-connected generation. (The model includes the Arnold, Stockton Mine, Stockton Plateau, and Lake Coleridge new generation projects). The approximate unit cost of various new generation options under MBIE's modelling is set out below (in the context of commenting on the economics of the proposed Waitaha scheme).

Ideally, the next project to be built should be the one with the lowest total cost (operating, capital and environmental). Decisions by the main market participants since around 2012 to cancel or defer indefinitely new generation projects not already committed show how market and internal commercial disciplines should work. In organisations where those disciplines are not as robust, there is some reason to be concerned.

More information on the new generation options for New Zealand is set out in section 9 of this report.

1.12 Supply and demand outlook for Westpower's region

Westpower states in its Waitaha application (at page 118):

> "Peak demand for electricity in the Westpower distribution area has been forecast to grow from 50 MW in 2012 to 70 – 80 MW by 2030, whilst electricity consumption is forecast to grow from 300 GWhs to 400 GWhs per annum by 2030. These growth rate forecasts incorporate possible new mining developments and ongoing growth in dairy farming and milk processing. This will increase the reliance on imported electricity via the national grid in the absence of new generating capacity on the West Coast"

As shown in the chart below, this forecast is not consistent with Westpower's forecast in its statutory Information Disclosures to the Commerce Commission, Transpower's forecast for the West Coast in its 2014 Annual Planning Report or MBIE's national demand growth projection.

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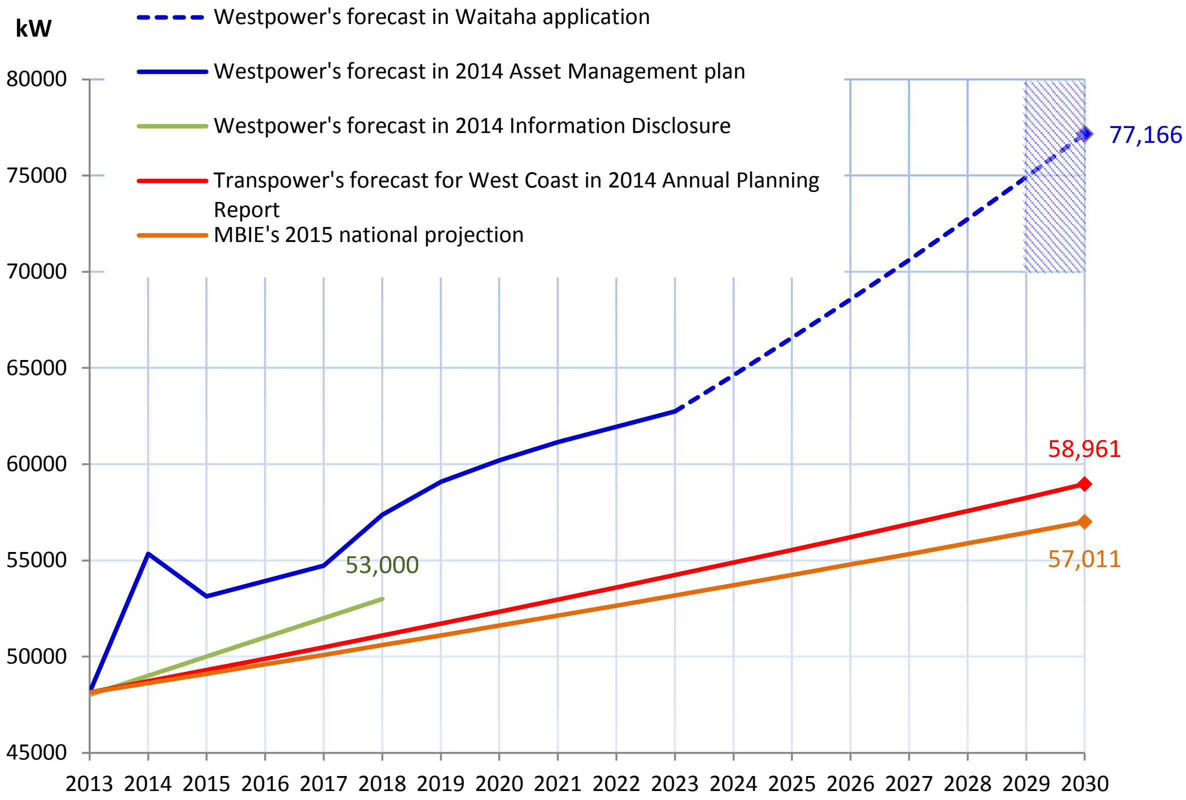


Based on the analysis in this report, and taking into account Westpower's poor track record in forecasting (as outlined in section 6.6 of this report), it is reasonable to conclude that Westpower's long term demand forecast of 70 – 80 MW by 2030 in its Waitaha application is more than questionable and provides no basis for medium term investment in new generation capacity.

The bulk of Westpower's forecast demand growth comes from the dairy industry. Dairy represents about 21% of GDP in Westland. Any increase in electricity demand from dairying depends primarily on future dairy commodity prices. Given the current outlook for the dairy sector, Westland Milk Products and its suppliers are likely to be rather cautious about expanding capacity in the medium term. Westpower's forecast of 8 to 13 MW of growth in electricity demand from the diary sector between 2013 and 2023 is likely to be premature.

Westpower's other main source of expected demand growth relies on Solid Energy establishing a new open-cast coal mine near Strongman, which could increase its electricity demand by about 4 MW in 2018. Given Solid Energy's challenging financial position, technical issues at Strongman, and the current medium term outlook for coal prices, it is reasonable to conclude that the prospects of establishing a commercial open-cast mine at Strongman during Westpower's forecast period has a low probability and therefore Westpower's forecast of an additional 4 MW of electricity demand in 2018 must be quite unlikely.[8]

[8] In section 5.7.4 of its Asset Management Plan for 2014 – 2024 at page 149, Westpower refers to several possible coal mining developments in the Rapahoe region and notes that: "Under the current economic circumstances, these projects are given a relatively low probability weighting". It is not clear if this is referring to the Strongman open-cast project.

Further, based on current evidence of the medium term outlook, Westpower's forecast step change in peak demand from 48.5 MW in 2014 to 62.7 MW in 2023, with the main growth coming from dairying and mining, would appear to have a low probability of occurring.

Drawing the above information together, the supply and demand situation on Westpower's network can be summarised as follows:

Current electricity supply capacity via transmission grid	50 MW
Plus current supply capacity of generation embedded	26 MW
Total current supply capacity	**86 MW**
Less current peak electricity demand (as at 31 March 2014)	48 MW
Current surplus peak capacity	**38 MW**

Applying the growth rate in Westpower's 2014 Information Disclosure, it would take 38 years to use up this surplus. It would take longer using Transpower's 2014 forecast, and even longer using MBIE's national growth forecast. Even applying Westpower's aggressive growth forecast in its Waitaha application, the existing surplus capacity would not be used up until around 2034 (20 years from now).

Further, as outlined above, Westpower reports that there are no constraints in its network or substations that would limit demand growth. It is therefore clear that no additional generation capacity is required to meet expected demand growth on Westpower's network.

In its 2014 Asset Management Plan, Westpower acknowledges the 2011 transmission upgrade delivered security of supply:

> "Currently, there is sufficient n-1 transmission capacity available in the transmission network feeding the West Coast, to ensure that major new loads can be supplied on an uninterruptible basis, and so **electricity supply should not be a constraint to future economic development.**" [Emphasis added]

Well into the future, at a time when existing supply capacity feeding Westpower's network is becoming insufficient to meet demand, additional capacity can be provided at a relatively low cost by upgrading capacitor banks and the like at grid exit points to enable greater capacity to be delivered on the Dobson transmission lines.

More information on the electricity supply and demand outlook for Westpower's network is set out in section 10 of this report.

1.13 Economics of Waitaha scheme

1.13.1 Test of financial viability

As noted above, in the absence of sufficient data for a full discounted cashflow analysis, the orthodox test for assessing whether a new generation project is likely to be financially viable is to measure whether wholesale prices likely to be received over the medium to longer term for electricity sold from the proposed scheme are, on average, above or below the full cost of producing it – if below, the proposed scheme is negative in net present value terms, which means it is neither an efficient choice of new generation nor financially viable.

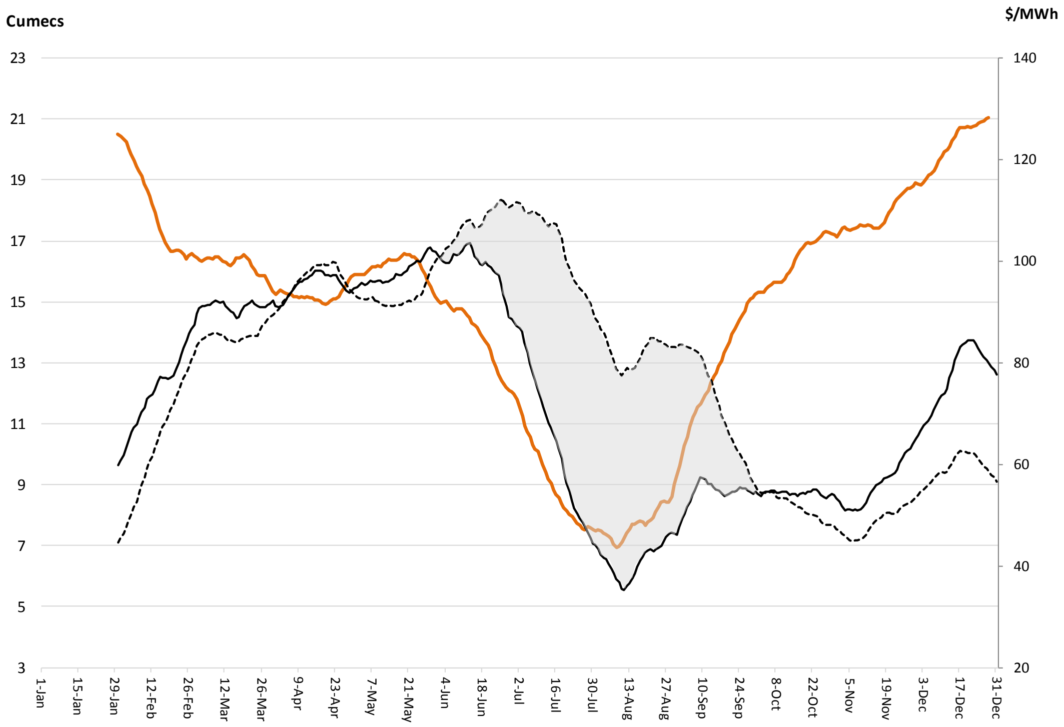
1.13.2 Generation-weighted price

Expected wholesale prices over the medium to longer term for New Zealand are outlined in section 8.5 of this report. This price path can be compared to the likely cost of supplying electricity from the proposed Waitaha scheme to give a general indication of whether the scheme is likely to be financially viable. However, this can be made more granular – that is, more specific to the Westpower's context – by adjusting the expected price path to reflect transmission 'location factors' – that is losses and any constraints – in delivering electricity to Westpower's network. (These are explained in section 3 of this report). Wholesale prices are then established at Westpower's grid exit points, which would be the price reference points for electricity supplied by the proposed Waitaha scheme.

The next level of granularity is to adjust the prices at Westpower's grid exit points to reflect the volumes of water that the Waitaha scheme is likely to have available each day for electricity production and match it with the prices at Westpower's grid exit points when those volumes of water used. This gives a 'generation-weighted' price.

The estimated generation-weighted price for the Waitaha scheme relative to daily water 'take' volumes is shown in the chart below. As shown in the shaded area of the chart, Waitaha power would typically miss the normal high price period during winter and early spring.

[Explanation: The dotted black line is the 30 day moving average of prices at HKK0661 (use right hand axis). The solid black line is the 30 day moving average of generation-weighted prices (use right hand axis). The orange line is the 30 day moving average of 'take' volumes for generation (use left hand axis). This is based on hydrology data provided by Westpower to Whitewater NZ for March 2006 to April 2012].



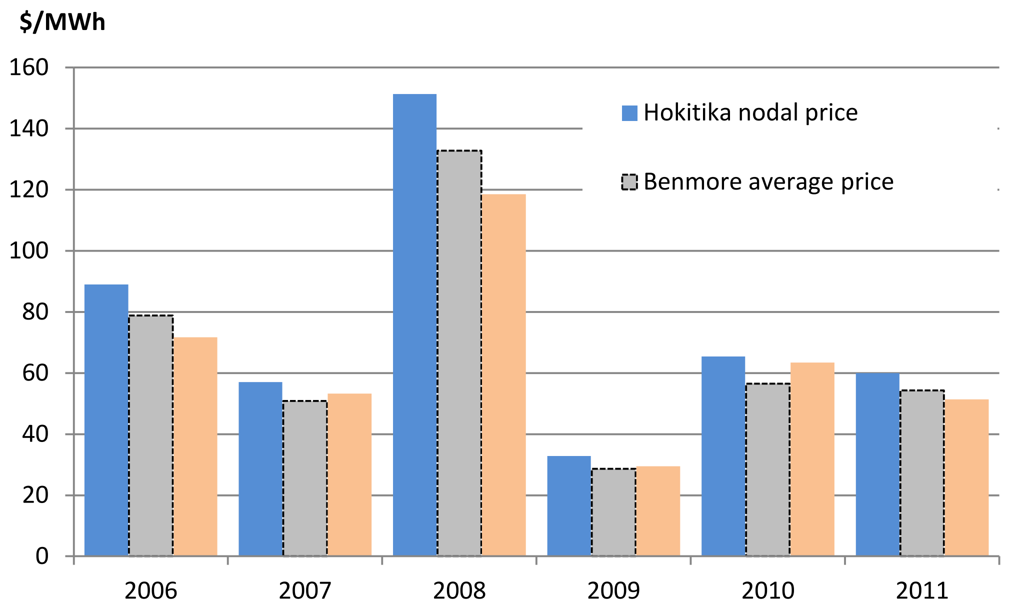
The analysis indicates that Waitaha inflows and 'take' volumes follow a very similar seasonal pattern to the Waitaki scheme, and that they do not capture the full price at Westpower's off-take node.

This is at odds with Westpower's claim in its Waitaha application (at page 120):

> "Also in relation to security of supply, the Scheme will provide geographic diversity of supply of electricity from hydro generating stations, which in the South Island are heavily dependent upon water catchments and climatic conditions in South Canterbury and Otago."[9]

Comparing annual average prices indicates that the Waitaha scheme's annual average generation-weighted price would be reasonably close to projections of the annual average wholesale price at the Benmore node outlined in section 8.5 of this report. As shown in the chart below, the annual average Waitaha generation-weighted price for 2006 to 2011 was lower than the annual average Benmore price for the same period.

[9] Westpower's Waitaha application at page 120



To be financially viable, the Waitaha scheme's 'unit cost' – that is, the full cost of producing a unit of power from the Waitaha – must be not greater than the generation-weighted price received for the power (on average over the medium term to longer term). As shown above, the Waitaha's generation-weighted prices are lower on average than average prices at Westpower's grid exit points and, in some years, also lower than average prices at Benmore. This sets a more demanding ceiling on the proposed scheme's 'unit cost'.

1.13.3 Estimated unit cost of Waitaha scheme

The key components of the unit cost for an electricity generation scheme are its variable operating and maintenance costs (**VOM**), fixed operating and maintenance cost (**FOM**) and capital costs, all expressed relative to electricity output:

Unit Cost ($/MWh) = **FOM** ($/MWh) + **VOM** ($/MWh) + **Capital charge** ($/MWh)

For hydro generation, operating and maintenance costs are comparatively low. In MBIE's model, estimated FOM and VOM (combined) amount to approximately 2% to 2.7% of unit costs for the top eight new hydro generation options as ranked by lowest project LRMCs in MBIE's model. The main component is the capital charge, which is the total capital cost amortised over an appropriate economic period using an appropriate discount rate.

Westpower has not disclosed its estimated capital charge for the proposed Waitaha scheme.
Deriving a reasonable estimate requires several input variables. The level at which those variables are set can have a significant impact on the level of the capital charge. However, in the absence detailed project data, a reasonable desk-top proxy is to derive a capital charge for the Waitaha scheme that would enable its unit cost ('project LRMC') to be compared on a like-for-like basis with hydro generation proposals in MBIE's 2015 LRMC rankings, which are set out in sections 9.7 and 13.5 of this report.

The total capital cost of the Waitaha project is not known. Westpower will have a range of estimates based on its feasibility work. However, the total cost is unlikely to be known within a narrower range (of say +/-15%) until more detailed design and assessment work has been completed.

Variations in the capital cost and annual output (GWh) have a significant impact on capital charge and therefore unit cost (or project LRMC). The approach adopted in this report is to establish a range for the Waitaha's unit cost based on a range of possible capital costs and GWhs of output per year. This is shown in charts set out in section 11.7 of this report.

Applying the methodology outlined above (and in more detail in section 11.7 of this report), the Waitaha scheme's estimated unit cost ranges from **$94.78**/MWh to **$109.90**/MWh. On MBIE's 2015 rankings:

- A unit cost of $94.78/MWh would put the Waitaha scheme about **9th** from the top out of 28 projects (where top is the least cost and bottom is the highest cost). This assumes the Waitaha's capital cost totals $95m and it delivers 120 GWh pa.

- A unit cost of $109.90/MWh would put the Waitaha scheme about **26th** from the top out of 28 projects (where top is the least cost and bottom is the highest cost). This unit cost comes about under various scenarios, including:

    - Total capital cost of $120m and 120 GWh pa;
    - Total capital cost of $115m and 115 GWh pa; or
    - Total capital cost of $100m and 110 GWh pa.

The estimated capital cost of the Waitaha scheme was reported in 2012 to be $100m (in NZ$2014). If this was so and the scheme output was 120 GWh pa, its unit cost (or 'project LRMC') would be about **$98.39** using the MBIE framework. This would put the Waitaha scheme about **13th** from the top out of 28 projects (where top is the least cost and bottom is the highest cost), 20 of which are already fully consented.

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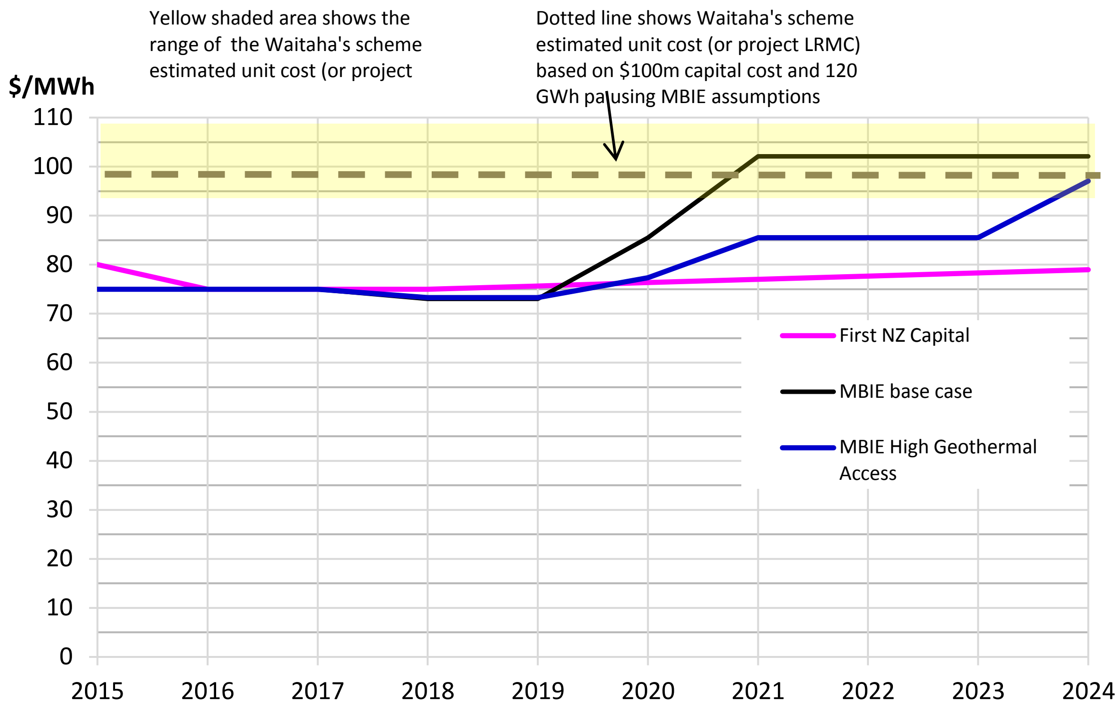
Rank	Type	Project	Fully consented	MW	Typical GWh pa	Capital cost $m	Variable O&M,	Fixed O&M,	LRMC $/MWh
1	Geothermal	Tauhara stage 2	Yes	250	1971	1201	0.00	105.00	79.06
2	Gas - CCGT	Otahuhu C	Yes	400	2803	610	4.30	35.00	83.04
3	Hydro	Hawea Control Gates	Yes	17	74	53	0.86	6.38	87.49
4	Wind	Hauauru ma raki stage1	Yes	252	975	627	3.00	50.00	89.43
5	Wind	Hauauru ma raki stage2	Yes	252	975	627	3.00	50.00	89.43
6	Hydro	Lake Pukaki	Yes	35	153	114	0.86	6.38	90.45
7	Gas - CCGT	Rodney CCGT stage 1	Yes	240	1682	384	4.30	35.00	91.27
8	Gas - CCGT	Rodney CCGT stage 2	Yes	240	1682	384	4.30	35.00	91.27
9	Wind	Turitea	Yes	183	708	478	3.00	50.00	94.91
10	CCGT	PropopsedCCGT1	Proposed	194	1360	333	4.30	35.00	95.01
11	Wind	Hawkes Bay windfarm	Yes	225	780	560	3.00	50.00	96.68
12	Geo	Tikitere LakeRotoiti	Applied	45	355	303	0.00	105.00	97.53
13	Hydro run of river	Waitaha	No	20	120	100	0.86	6.38	98.39
14	Wind	Project CentralWind	Yes	120	416	314	3.00	60.00	99.05
15	Hydro	Arnold	Yes	46	201	192	0.85	6.38	99.51
16	Hydro	Lake Coleridge 2	Applied	70	307	289	0.85	6.38	102.4
17	Hydro run of river	Stockton Mine	Yes	35	153	135	0.80	6.38	103.2
18	Wind	Waitahora	Yes	156	541	408	3.00	50.00	105.5
19	Wind	Puketoi	Applied	159	551	416	3.00	50.00	105.6
20	Wind	CastleHill stage1	Yes	200	693	513	3.00	50.00	106
21	Wind	CastleHill stage2	Yes	200	693	513	3.00	50.00	106
22	Wind	CastleHill stage3	Yes	200	693	513	3.00	50.00	106
23	Geothermal	Rotoma LakeRotoma	Applied	35	276	260	0.00	105.00	106.2
24	Geothermal	Kawerau TeAhiOMaui	Applied	10	79	76	0.00	105.00	107.8
25	Wind	Taharoa	Yes	54	209	166	3.00	60.00	109.2
26	Hydro (SC)	North Bank Tunnel	Applied	260	1139	1045	0.84	6.38	109.2
27	Hydro run of river	Stockton Plateau	Yes	25	110	106	0.86	6.38	111.8
28	Hydro run of river	Wairau	Yes	70	307	297	0.70	6.38	112.1

1.13.4 Caveat

Just as MBIE caveats its model, the estimates above are not necessarily the Waitaha scheme's unit cost. Underlying cost assumptions will vary from one approach to another. The methodology applied in this report compares the proposed Waitaha scheme with other new generation projects in MBIE's model on a 'like for like' basis.

1.13.5 Would the Waitaha scheme be financially viable?

Applying the test outlined above, is the average wholesale electricity price over the next five years expected to be equal to or greater than the Waitaha scheme's estimated unit cost (or 'project LRMC') of between $94.78/MWh and $109.90/MWh? Based on the price paths set out in this report, the answer is no. Based on the analysis in this report, it is therefore unlikely that the proposed scheme would be financially viable in the reasonably foreseeable future.



When is it likely to become financially viable? This depends on three key factors (among others):

- Future wholesale prices – whether they rise and, if they do, the rate at which they rise.
- The level of the scheme's capital cost – It is reasonable to assume that capital costs are more likely to rise than fall over the coming years. As shown above, relatively small increases in capital cost increase the scheme's unit cost, which means a higher average wholesale price would be required for the scheme to be financially viable.
- The level of electricity output that the scheme would produce – relatively small decreases in assumed output increase the scheme's unit cost, which means a higher average wholesale price would be required for the scheme to be financially viable.

As outlined in this report, there is a reasonably clear consensus, which has been in place for the last two years or so, that wholesale prices are likely to remain flat for the medium term, particularly given low demand growth and continuing surplus capacity. Beyond 2020, the price path is not clear:

- Under MBIE's draft base case scenario, the Waitaha scheme could become viable from around 2021.
- Under MBIE's high geothermal availability scenario, it would not become viable until 2024 or even 2027.
- Under First NZ Capital's wholesale price projection, it would not be economic even by 2024.

In reality, prices beyond 2020 are too uncertain to forecast with any confidence. Some of the relevant factors are outlined in section 8.5 of this report. At best, any current view of prices beyond 2020 is simply a scenario (one of many) against which changes in the market can be monitored.

What can be reasonably concluded now in relation to the Waitaha scheme's financial viability beyond 2020 is this:

- For it to become viable around 2021 would required a relatively sudden and substantial rise in wholesale prices – .
- Such a substantial rise over such a short duration would seem unlikely based on current information and previous patterns of structural change in medium to longer term wholesale prices.[10]
- There are a significant number of fully consented new generation projects that appear to have materially lower unit costs than the Waitaha scheme.
- It would not be sensible, for the New Zealand electricity system or electricity consumers on Westpower's network, for the Waitaha scheme to be built ahead of new generation options with a lower unit cost.
- As the 2009 Ministerial Review observed: "It is important to minimise the costs of new generation, get the right generation built, and ensure that alternatives such as energy efficiency are fully exploited."[11]

More information on whether the proposed Waitaha scheme is likely to be financially viable is set out in section 11 of this report.

[10] See 2009 Ministerial Review, Volume 1, Figure 8 at page 40

[11] "Ministerial Review of Electricity Market Performance", Electricity Technical Advisory Group and the Ministry of Economic Development, August 2009, Volume 1, para 54

1.14 Westpower's reasons for Waitaha scheme

As noted above, section 17S(2) requires a applicant to supply, in addition to the contents required by section 17S(1):

> "**reasons for the request** and sufficient information to satisfy the Minister, in terms of section 17U, that it is both **appropriate** to grant a lease, *profit à prendre*, licence, or easement and lawful to grant it" [emphasis added]

The reasons given by Westpower in its Waitaha application are as follows:

- To meet growth in demand for electricity,
- Self-sufficiency in electricity and community ownership,
- Security of supply,
- Transmission losses,
- Confidence to investors in the West Coast, and
- Reducing carbon emissions

These reasons are examined in section 12 of this report. It is apparent that they are either not supported by the evidence or are not relevant under Part 3B of the Act. Individually or together, Westpower's reasons do not provide sufficient reason to conclude that it would be appropriate under Part 3B of the Act to authorise an activity in a conservation area that would impose adverse effects.

1.15 Alternative locations for activity

As noted above, section 17U (4)(a) of the Act provides that the Minister is not allowed to grant a concession under Part 3B of the Act if he or she is satisfied the activity could reasonably be undertaken in another location that is outside the conservation area to which the application relates; or in another conservation area or in another part of the conservation area to which the application relates, where the potential adverse effects would be significantly less.

The "activity" in question is "the business of generating electricity". Under section 17U(4)(a), this activity does not have to be undertaken by the applicant at the alternative location. Further, the alternatives to be considered are not at law required to be limited to only generation options undertaken by Westpower, or only options that would be embedded within Westpower's network. Nor are the alternative locations limited to the West Coast. Given that, for the reasonably foreseeable future, the Waitaha scheme is neither needed nor financially viable, the alternatives to be considered for the purposes of section 17U(4)(a) should include electricity generation options that may become financially viable within the same timeframe as the Waitaha scheme may become needed and viable.

(Even if the "activity" in this case were defined as "the business of electricity generation that will contribute to meeting future electricity demand in Westpower's region", the range of alternative locations to be considered for the purposes of section 17U(4)(a) is still wide).

From a legal perspective, Westpower's Waitaha application is therefore not complete in that it does not address alternatives on the terms required by section 17U(4)(a), as outlined above.

Alternatives to the Waitaha scheme include (in no particular order) the:

- Additional generation from existing generation stations
- Lake Hawea control gates scheme
- Lake Pukaki canal option;
- Any of the other new generation schemes in New Zealand already consented;
- Arnold hydro scheme; and
- Stockton mine and Stockton plateau hydro schemes.

Each of these is alternatives is outlined in section 13 of this report. Each is already fully consented. Based on this analysis, it is reasonable to conclude that there is a wide range of alternative locations within the relevant time-frame at which the activity in question could be reasonably undertaken outside the relevant conservation area. Under section 17U(4)(a) of the Act, the Minister is therefore not allowed to grant concessions for the activity proposed by Westpower in relation to the Waitaha scheme.

1.16 Conclusions

The key conclusions of this report are set out in section 1.2 above

2. Statutory regime and purpose of report

2.1 Outline of this section

This section 2 is divided into the following parts:

- Process to date
- Statutory regime
  - Relationship with the Resource Management Act 1991
  - Overview of statutory regime
  - Effects of activity
  - Statutory purpose
  - "Appropriate" test
- What is the "activity" in relation to the proposed Waitaha scheme?
- Legal relevance of financial viability and electricity need
  - Financial viability
  - Electricity need
- Alternative locations for activity
- Relevance of Amethyst precedent
- Is Westpower's application 'complete'?
- Purpose of this report
- Approach in this report
- Diagrams of statutory process

2.2 Process to date

Westpower has applied to the Minister of Conservation for concessions to carry out various activities in relation to a proposed hydro-electric generation scheme on conservation land in and around the Waitaha River.

Westpower's application is dated July 2014. A covering letter from Westpower to the Department of Conservation ('DOC') is dated 29 July 2014. A copy of that application was released by DOC under the Official Information Act on 25 February 2015.

Westpower's application contains a range of reports from various consultants relating to various effects if the scheme were to proceed. A report prepared by Douglas Rankin and Shane Orchard on the impacts of the proposed scheme in relation to white water and kayaking values was provided to DOC in February 2015.

DOC is considering Westpower's application and preparing advice for the Minister of Conservation. DOC has advised Whitewater NZ that, if the Minister intends to grant concessions, it is aiming to issue the required public notification toward the end of May 2015.

2.3 Statutory regime

2.3.1 Relationship with the Resource Management Act 1991

The statutory regime for granting concessions is separate and distinct from the statutory regime for granting resource consents. As the Parliamentary Commissioner for the Environment has highlighted:

> "The role of the Minister of Conservation is very distinct from that of decision-makers in the resource consent process and should not be compromised. The core of the Conservation Act is the preservation of New Zealand's natural heritage. This is very different from the broader considerations in the RMA"[12]

This is reflected in section 17P of the Conservation Act 1987, which provides that, except in relation to any lease granted by the Minister, completing the concession granting process under Part 3B does not relieve any person from any obligation to obtain a resource consent under the Resource Management Act 1991.

2.3.2 Overview of statutory regime

The regime relating to concession for activities on conservation land is set out in Part 3B of the Conservation Act 1987.

With certain limited exceptions, any non-recreational activity in conservation areas is prohibited unless authorised by a concession[13]. A concession may be in the form of a lease, licence, permit, or easement[14]. The range of activities covered is very wide. In the Act, "activity" is defined to include a trade, business, or occupation[15].

A non-recreational activity in a conservation area may be authorised by the Minister within certain limits and subject to various criteria:

- If it does not comply with, or is inconsistent with, the provisions of the Act or any relevant conservation management strategy or conservation management plan, it must be declined.[16]

- If the proposed activity is contrary to the provisions of this Act or the purposes for which the land concerned is held, it must be declined.[17]

- If the proposed activity could reasonably be undertaken in another location that is outside the conservation area, or in another conservation area where the potential adverse effects would be significantly less, it must be declined.[18]

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[12] Parliamentary Commissioner for the Environment, "Hydroelectricity or Wild Rivers? Climate Change Versus Natural Heritage", May 2012, at page 66 www.pce.parliament.nz/assets/Uploads/Wild-Riversweb.pdf

[13] s.17O(1), Conservation Act 1987

[14] s.17Q, Conservation Act 1987

[15] s.2(1), Conservation Act 1987

[16] s.17T(2), Conservation Act 1987

[17] s.17U(3), Conservation Act 1987

- The Minister may decline it if there are no adequate or reasonable methods for remedying, avoiding or mitigating the adverse effects of activity, structure or facility.[19]

- The Minister may also decline it if information is insufficient or inadequate.[20]

- If an application is complete, it is not required to be declined under one of the three categories referred to above, there is sufficient information, and there are adequate or reasonable methods for remedying, avoiding or mitigating adverse effects, then:

  — If the proposed concession is a lease, *profit à prendre*, licence, or easement, the Minister may authorise the proposed activity if he or she is to be satisfied[21] that it is both appropriate and lawful[22]. (Note that "appropriate" is a higher threshold than simply "lawful").

  — If the proposed concession is a permit, the Minister is not required to grant it if he or she considers that it is inappropriate in the circumstances of the particular application having regard to various matters[23].

Note the subtle but important difference of language in the last two points:

- If it is a lease, *profit à prendre*, licence, or easement, the Minister must be satisfied it is both appropriate and lawful. If it is not, the Minister may not grant the concession.

- By contrast, if it is a permit only and it is inappropriate, the Minister is not required to grant it. This leaves room for the Minister to grant a permit if it is inappropriate but still lawful. In other words, the dual threshold does not necessarily apply to a proposed permit[24].

As outlined in Table 7 of its Waitaha application, Westpower is seeking concessions in the form of leases, licences and easements.

The decision-making steps that the Minister is to follow under Part 3B of the Act is shown in flow diagrams in section 2.11 of this report below.

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[18] s.17U(4)(a), Conservation Act 1987

[19] s.17U(2)(b), Conservation Act 1987

[20] s.17U(2)(a), Conservation Act 1987

[21] Satisfied in terms of s.17U

[22] s.17S(2). Noted in Court of Appeal in Otehei Bay Holdings Ltd v Fullers Bay of Islands Ltd [2011] NZCA 300 at para 47

[23] The matters set out in s.17U – see s.17T(3)

[24] While s.17T(3) refers to any type of concession, a lease, *profit à prendre*, licence or easement is subject to s.17S(2), which requires the Minister to be satisfied that the proposed activity is both appropriate and lawful. The only form of concession not included in s.17S(2) is a permit given that a concession under s.17Q is confined to a lease, licence, permit, or easement.

2.3.3 Effects of activity

At the stage when the Minister is deciding whether a proposed activity is appropriate and lawful, the various matters considered include the effects of a proposed activity. In the Act, "effects" has the same meaning as in the Resource Management Act 1991, which defines "effects" as including[25]:

- Any positive or adverse effect; and
- Any temporary or permanent effect; and
- Any past, present, or future effect; and
- Any cumulative effect which arises over time or in combination with other effects—

regardless of the scale, intensity, duration, or frequency of the effect, and also includes—

- Any potential effect of high probability; and
- Any potential effect of low probability which has a high potential impact.

"Effects" includes social, cultural and economic effects[26]. Under the concession regime, the Minister also considers any measures to avoid, remedy or mitigate any adverse effects[27].

2.3.4 Statutory purpose

Under public law, the Minister must exercise his or her powers in a manner that gives effect to the objective or purpose of the statute under which the powers are conferred – in this case, the Conservation Act 1987. The clear purpose from the long title of the Conservation Act is:

> "...to promote the **conservation** of New Zealand's natural and historic resources".
>
> "Conservation" means "the **preservation** and **protection** of natural and historic resources for the purpose of maintaining their intrinsic values, providing for their appreciation and recreational enjoyment by the public, and safeguarding the options of future generations".[28]
>
> "Preservation" means "the maintenance, so far as is practicable, of [a resource's] intrinsic values"[29]

[25] s.3, Resource Management Act 1991

[26] For example, Schedule 4, clause 7(1)(a) – "An assessment of the activity's effects on the environment must address the following matters: (a) any effect on those in the neighbourhood and, where relevant, the wider community, including any social, economic, or cultural effects"

[27] s.17U, Conservation Act 1987

[28] s.2, Conservation Act 1987

[29] s.2, Conservation Act 1987

> "Protection" means "maintenance, so far as is practicable, [of a resource] in its current state; but includes (a) its restoration to some former state; and (b) its augmentation, enhancement, or expansion."[30]

At law, this statutory purpose informs what activities are "appropriate" under Part 3B.

2.3.5 "Appropriate" test

So –

- If an application for a concession under Part 3B is (i) complete, (ii) not required to be declined under one of the three categories referred to above, (iii) there are adequate or reasonable methods for remedying, avoiding or mitigating adverse effects, **and** (iv) there is sufficient information to assess effects, then –

- The Minister weighs the effects of the proposed activity and other relevant factors (on the one hand) against the conservation values of the relevant conservation area (on the other), making a decision that gives effect to the statutory purpose of the Conservation Act 1987.

If the concession sought is a lease, *profit à prendre*, licence, or easement, the Minister must be satisfied it is both appropriate and lawful.[31] If it is not, the Minister may not grant the concession.

If the concession sought is a permit and it is inappropriate, the Minister is not required to grant it but (by implication in the legislation) may, at his or her discretion, do so if it is lawful.

As outlined in Table 7 of its Waitaha application, Westpower is seeking concessions in the form of leases, licences and easements.

2.4 What is the "activity" in relation to the proposed Waitaha scheme?

Westpower's Waitaha application seeks concessions to construct, use and maintain certain specific structures and facilities that form part of the hydro scheme, including headworks, subsurface structures, powerhouse site, access road and transmission lines. In essence, these are the structures and facilities that would form the scheme's footprint on conservation land. Clearly, the scheme includes other elements, some of which would be housed within some of those structures and facilities. The types of concessions that Westpower is seeking are summarised in Tables 6 and 7 of its Waitaha application.

The legislation clearly distinguishes between "activity", "structure" and "facility".[32] The "activities" involved in building, operating and maintaining the scheme would require authorisation. In addition, each of the structures and facilities comprising the scheme that would remain when the scheme had been completed would require authorisation to occupy the relevant conservation areas.

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[30] s.2, Conservation Act 1987

[31] s.17S(2). Noted in Court of Appeal in Otehei Bay Holdings Ltd v Fullers Bay of Islands Ltd [2011] NZCA 300 at para 47

[32] See for example s.17U(2)(b

However, "activity" in the Act is defined to "include a trade, business, or occupation"[33], which is distinct from the construction and engineering activities involved in building, operating and maintaining the scheme, or the continuing occupation of the conservation area by the structures and facilities. The overall activity that Westpower is proposing to undertake is "the business of generating electricity", which under section 17O is not permitted in a conservation area unless authorised by a concession.

2.5 Legal relevance of financial viability and electricity need

The required contents of any application under Part 3B are prescribed in sections 17S(1) and 17S(2) of the Act. The matters to be considered by the Minister are set out in section 17U.

2.5.1 Financial viability

Financial viability is a distinct matter to be considered by the Minister in deciding whether to grant a concession. As the Minister stated in his decision on the application by Riverstone Holdings Limited ('RHL') for a proposed monorail in Fiordland:

> "it is common sense to look at financial viability when I, as Minister, decide whether to give the Crown's "landowner" permission to use the public land"[34]

In weighing the issue of financial viability in that case, the Minister stated:

> "I appreciate that the question of whether the monorail would, or would not, prove viable is not something that can be conclusively proved one way or the other in advance. Having said that, I must make a decision on the information available. Even after considering the updated...figures, I consider it more likely than not that the monorail would not be financially viable."[35]

Strong reservations about financial viability were one of five distinct reasons given by the Minister for declining RHL's application.[36]

The relevant test of financial viability in relation to new electricity generation projects is outlined in section 5 of this report.

In relation to the proposed Waitaha scheme, the overall activity to be authorised by concessions is, as outlined above, "the business of electricity generation". The financial viability of that business is clearly a relevant legal consideration for the Minister in deciding whether to grant concessions.

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[33] s.2(1), Conservation Act 1987

[34] Letter dated 29 May 2014 from Minister of Conservation to Mr Bob Robertson, at para 38

[35] Letter dated 29 May 2014 from Minister of Conservation to Mr Bob Robertson, at para 44

[36] Letter dated 29 May 2014 from Minister of Conservation to Mr Bob Robertson, at para 8(e)

If the activity in question is not financially viable, it would not be appropriate (and probably not lawful) in terms of 17S(2) of the Act to incur adverse effects on conservation values.[37] To authorise a non-viable business with such effects would be inconsistent with the Act's purpose, which as outlined above is "to promote the preservation and protection of natural and historic resources for the purpose of maintaining their intrinsic values, providing for their appreciation and recreational enjoyment by the public, and safeguarding the options of future generations."[38]

2.5.2 Electricity need

As noted earlier, section 17S(2) requires a applicant to supply, in addition to the contents required by section 17S(1):

> "**reasons for the request** and sufficient information to satisfy the Minister, in terms of section 17U, that it is both appropriate to grant a lease, *profit à prendre*, licence, or easement and lawful to grant it" [emphasis added].

In relation to the proposed Waitaha scheme, reasons for Westpower's request obviously include why it considers the proposed power scheme is needed. Westpower asserts that it is needed to meet future growth in electricity consumption:

> "Peak demand for electricity in the Westpower distribution area has been forecast to grow from 50 MW in 2012 to 70 - 80 MW by 2030, whilst electricity consumption is forecast to grow from 300 GWhs to 400 GWhs per annum by 2030. These growth rate forecasts incorporate possible new mining developments and ongoing growth in dairy farming and milk processing. This will increase the reliance on imported electricity via the national grid in the absence of new generating capacity on the West Coast".[39]

In Westpower's view, the proposed scheme is also needed for security of supply:

> "The [Waitaha] Scheme will provide some protection against situations when no or restricted external transmission capacity into the region is available...for business customers with high electricity reliance or consumption the costs can be more significant – either in terms of lost production or the requirement to invest in expensive back-up sources of electricity supply."[40]

Westpower's reasoning is reviewed in some detail in this report. From a legal point of view, it is clear under the Part 3B of the Act that, if the scheme is not needed, it is unlikely to be "appropriate" in terms of section 17S(2) of the Act to incur adverse effects on conservation values[41].

[37] That is, adverse effects after any measures to avoid, remedy or mitigate

[38] s.2, Conservation Act 1987

[39] Westpower's Waitaha application at page 118

[40] Westpower's Waitaha application at pages 7 and 120

[41] That is, adverse effects after any measures to avoid, remedy or mitigate

Westpower gives a range of other reasons as to why, in its view, the scheme is needed, which include reducing transmission losses, lowering carbon emissions, and giving the local community greater ownership and self-sufficiency in electricity generation, with potential benefits of lower electricity prices and improved economic confidence.[42] These are evaluated in section 12 of this report.

2.6 Alternative locations for activity

As noted above, the Minister is not allowed to grant a concession under Part 3B of the Act if he or she is satisfied the activity could reasonably be undertaken in another location that is outside the conservation area to which the application relates; or in another conservation area or in another part of the conservation area to which the application relates, where the potential adverse effects would be significantly less. This is set out in section 17U(4)(a).

As also noted above, the overall "activity" in question is "the business of generating electricity". Under section 17U(4)(a), the question is whether the "activity could reasonably be undertaken in another location." It does not have to be undertaken by the applicant.

A wide range of alternative locations for carrying the activity in question needs to be considered. Even if the activity were defined as "the business of electricity generation that assists meeting growth in electricity demand in Westpower's region", there are still many alternative locations to be considered for the purposes of section 17U(4)(a). This is discussed further in section 13 of this report.

2.7 Relevance of Amethyst precedent

The presumption in Westpower's application is that the Waitaha scheme should be treated as another Amethyst. This is a recurring theme in the Waitaha application, for example:

> "The recently commissioned Amethyst Hydro Scheme provides an excellent example of how Westpower approaches hydro-electric power scheme development in an environmentally sensitive manner... The Amethyst Hydro Scheme has a very small footprint and illustrates how significant advantages can accrue to the local community through small scale run-of-river hydro development. Westpower is committed to quality developments and sound environmental practices and expects to apply the same key success factors to the Waitaha Hydro Scheme" (Westpower's application, section 2.2, page 7)
>
> "Westpower have adopted this approach following completion of the Amethyst Hydro Scheme. That Scheme is of similar layout, although it differs in scale, and is also within conservation land. It has been successfully developed taking into account the site specific values and requirements and utilising the methodology outlined above" (Westpower's application, section 5.1, page 32).

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42 Westpower's Waitaha application at pages 3, 7, 8, 9 and 120

The clear implication is that the Waitaha scheme should be decided by the Minister with a similar outcome to the Minister's Amethyst decision.

However, the Waitaha scheme must be considered on its own merits without making any presumptions or assumptions on the basis of the Amethyst scheme, the Minister's evaluation of Westpower's Amethyst application, or the Minister's decision to grant concessions for the Amethyst scheme.

In short, the Waitaha scheme must to be assessed against the relevant statutory criteria independently of the Amethyst precedent. This approach is required by public law and Part 3B of the Act, in particular, section 17T(3), which provides that the Minister is not required to grant any concession:

> "...if he or she considers that the grant of a concession is inappropriate in the circumstances of **the particular application** having regard to the matters set out in section 17U [s.17T(3)]" [emphasis added].

2.8 Is Westpower's application 'complete'?

Section 17T(1) makes it clear that the Minister is only required to consider an application for concessions that is complete in terms of section 17S.

Westpower's Waitaha application does not contain any information on whether the proposed Waitaha scheme is financially viable. The report by Brown, Copland & Co in appendix 21 of the application does not address these matters – it is confined to claimed economic effects of the scheme on the local economy.

Westpower's Waitaha application also fails to outline the range of alternative locations for the overall activity that is to be authorised.

Westpower's application is therefore **not** complete in terms of section 17S of the Act.

2.9 Purpose of this report

The purpose of this report is:

- To advise DOC and the Minister that Westpower's application is not complete as defined by the Act for the reasons outlined in this report; and
- To provide a robust and objective assessment of:
  - Whether the reasons given by Westpower for the proposed Waitaha scheme are valid based on the evidence and relevant law for the purposes of Part 3B of the Act, in particular section 17S(2);
  - Whether the proposed scheme is likely to be financially viable; and

— Whether the activity to be authorised could reasonably be undertaken in another location that is outside the conservation area in question, or in another conservation area or in another part of the conservation area to which the application relates, where the potential adverse effects would be significantly less.

The Minister is invited to receive this report as:

- "a report from any person on any matters raised in relation to the application" for the purposes of section 17S(4)(a); and/or
- "existing relevant information on the proposed activity" for the purposes of section 17S(4)(b).

2.10 Approach in this report

This report provides a reasonably detailed evaluation of whether the proposed Waitaha scheme is needed from an electricity perspective. It also provides a desk-top analysis of whether the proposed scheme is likely to be financially viable.

Consistent with the requirements of Part 3B of the Act, this analysis is to be taken into account in deciding whether it is appropriate under the Act to authorise the proposed activity by granting concessions.

This report has been prepared from an independent and objective perspective. It has not been prepared to support or critique any particular party or position. The analysis and conclusions reflect the relevant available facts using standard methods of analysis in the industry.

2.11 Diagrams of statutory process

The legal steps, criteria and decision-making options under Part 3B fall into four steps:

- Step 1: Is the application complete in terms of the legislation? The Minister is only required to consider complete applications;
- Step 2: If it is not complete, the Minister has various options for obtaining further information;
- Step 3: In relation to complete applications, the legislation requires the Minister to decline an application if any of three conditions apply; and
- Step 4: If none of those three conditions apply, the Minister has discretion to approve or decline having regard to various mandatory considerations. To grant a lease, *profit à prendre*, licence or easement, it must be both appropriate and lawful. As outlined in Table 7 of its Waitaha application, Westpower is seeking concessions in the form of leases, licences and easements.

The Minister's decision is of course open to judicial review.

The four steps referred to above are shown in the following diagrams. The first provides an overview of the statutory process as a whole.

Figure 1: Overview - Minister's decision-making under Part 3B.
This first diagram provides an Overview of the whole decision-tree. Note that the 'step' boxes have the

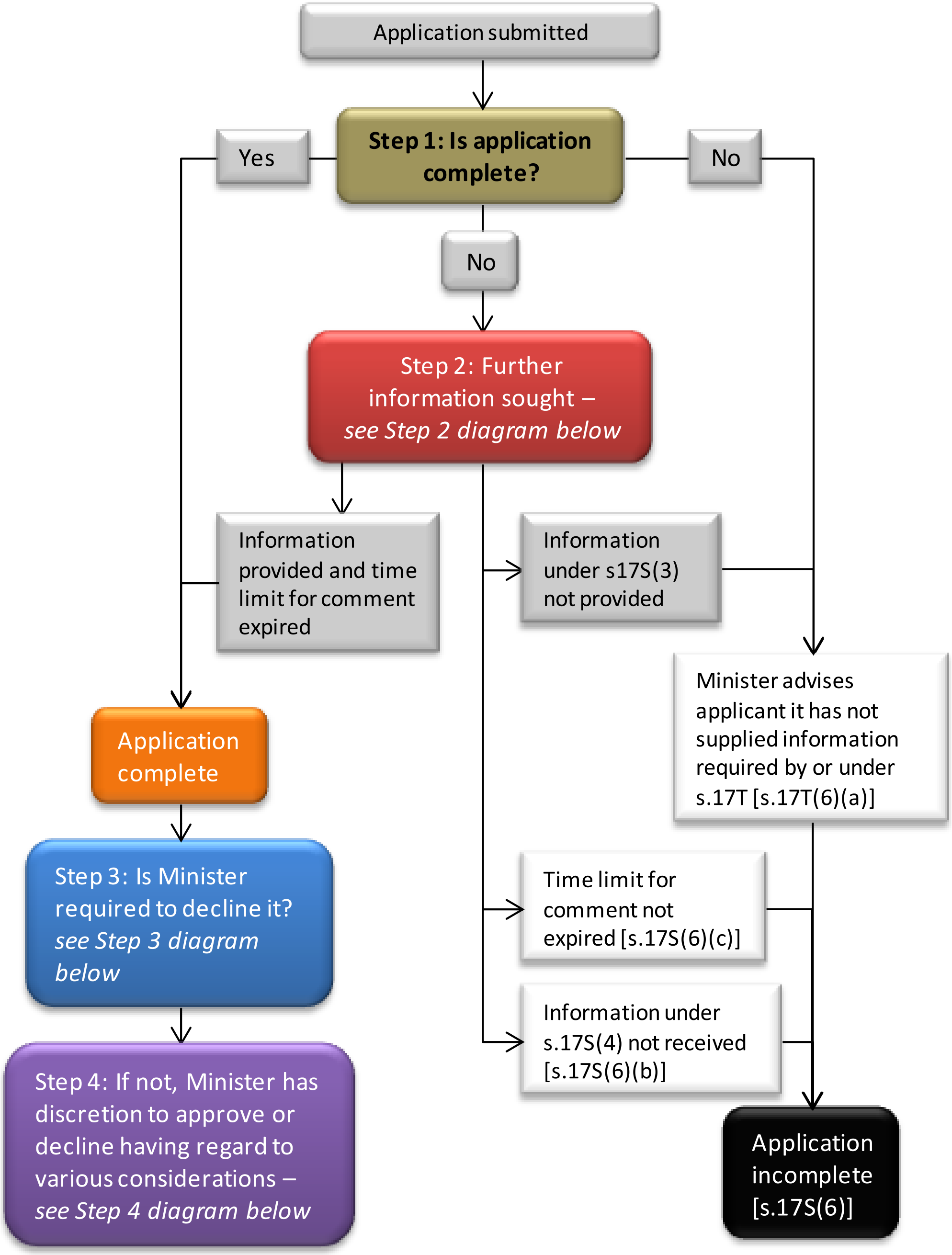


Figure 2: Step 1 – Is the application complete?

The Minister is only required to consider complete applications [s.17T(1)]. The three options are shown below.

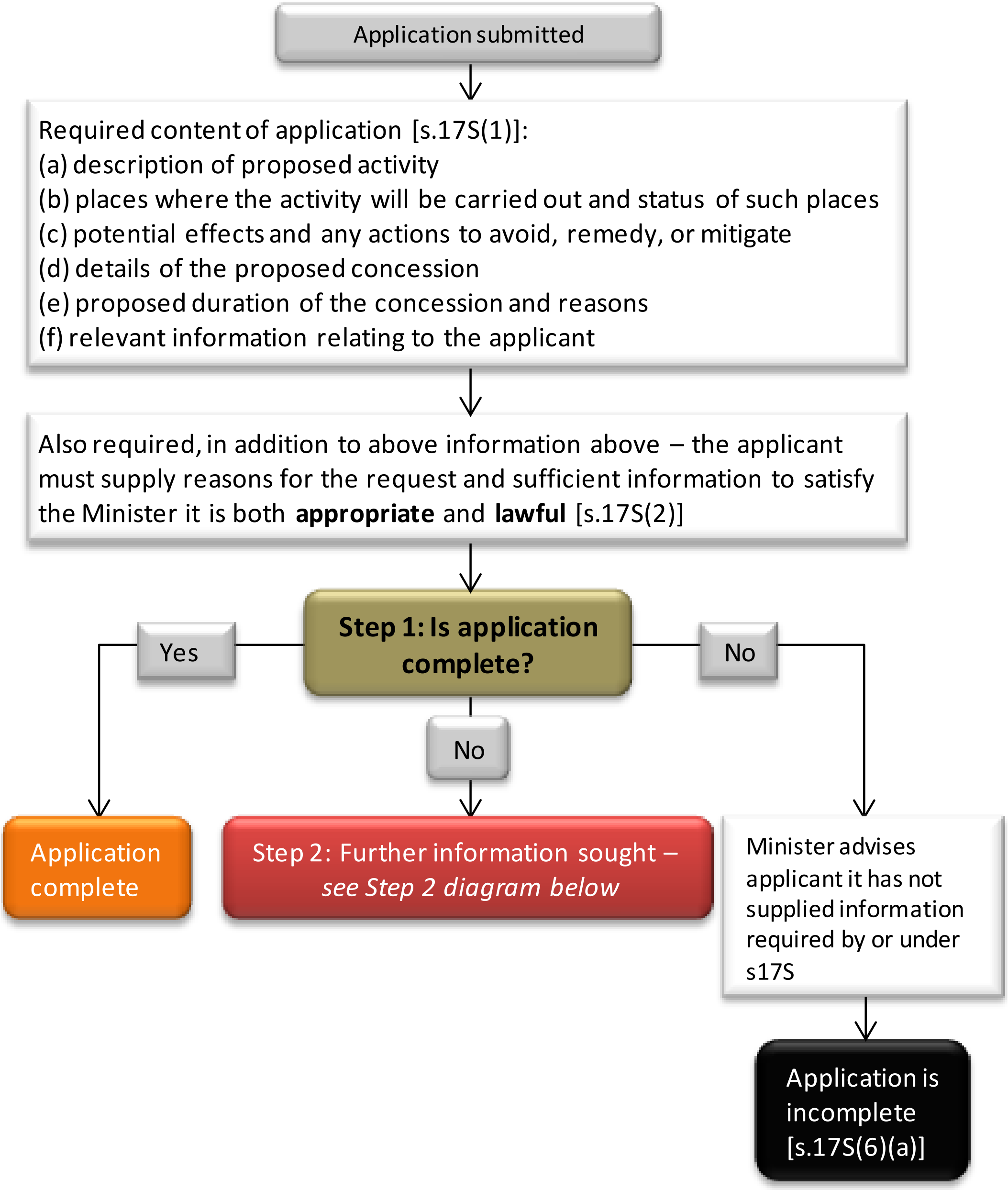


Figure 3: Step 2 – Further information

If application is incomplete and further information is sought.

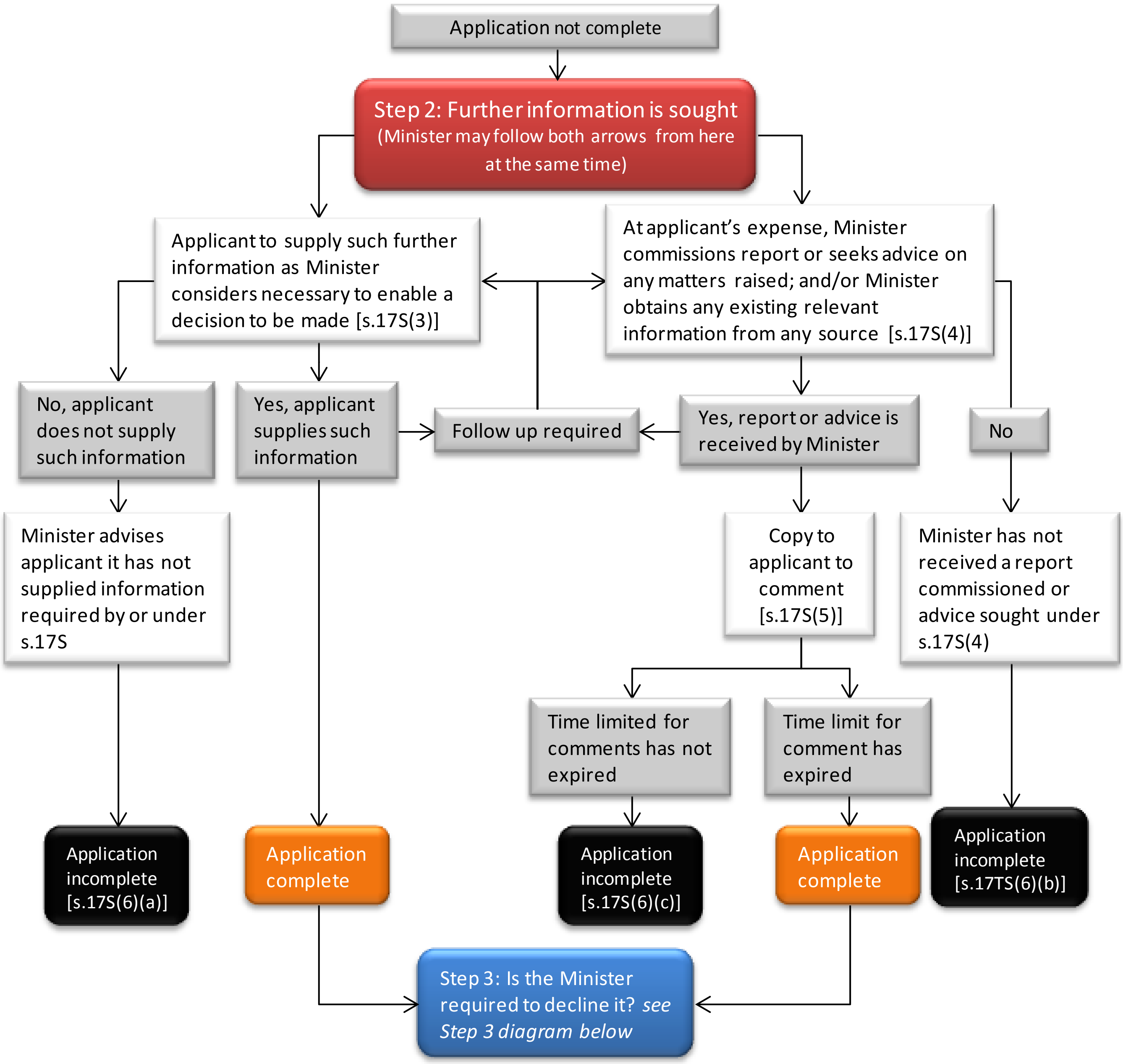


Figure 4: Step 3 – Is the Minister required to decline it?

The legislation requires the Minister to decline an application if any of three conditions apply

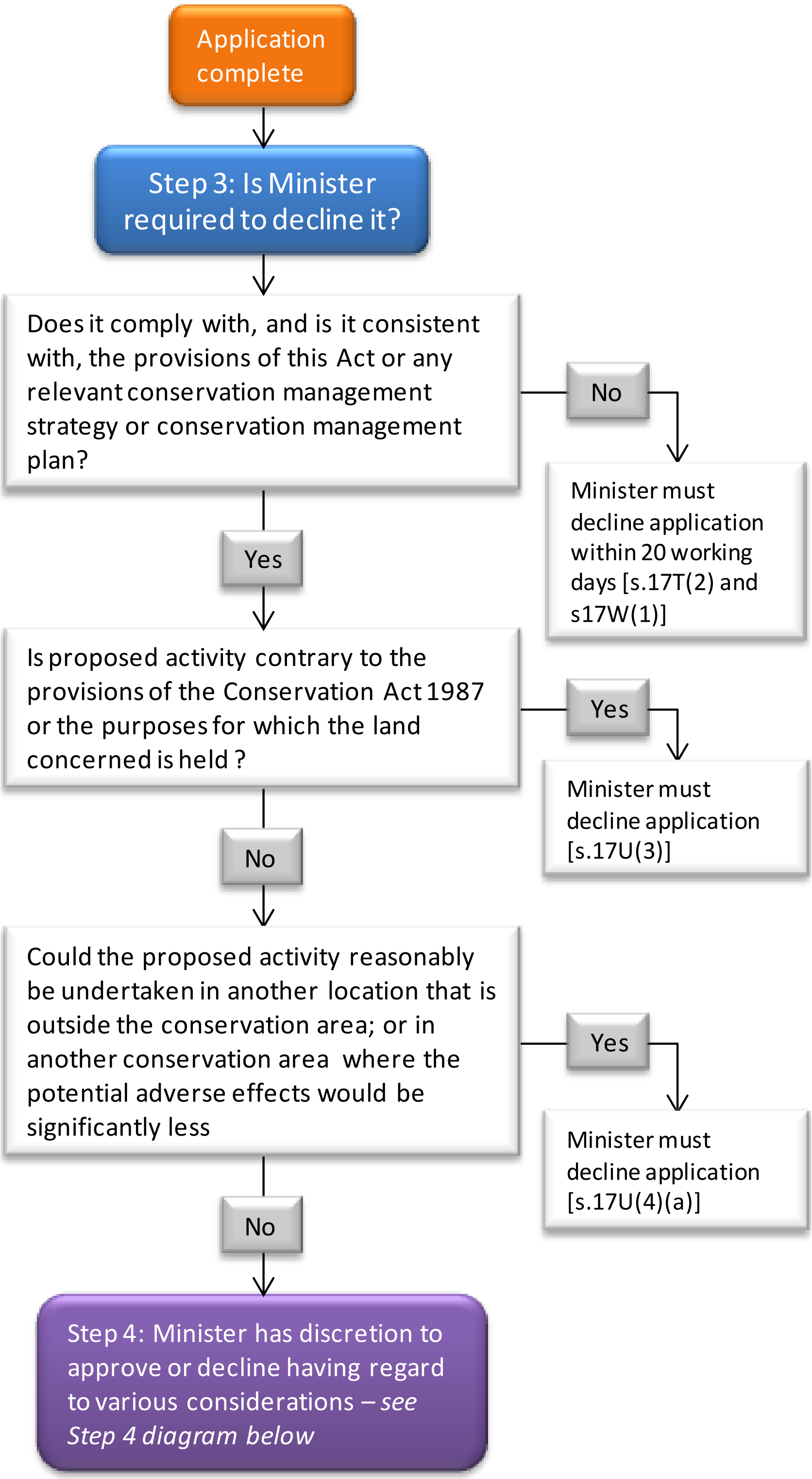
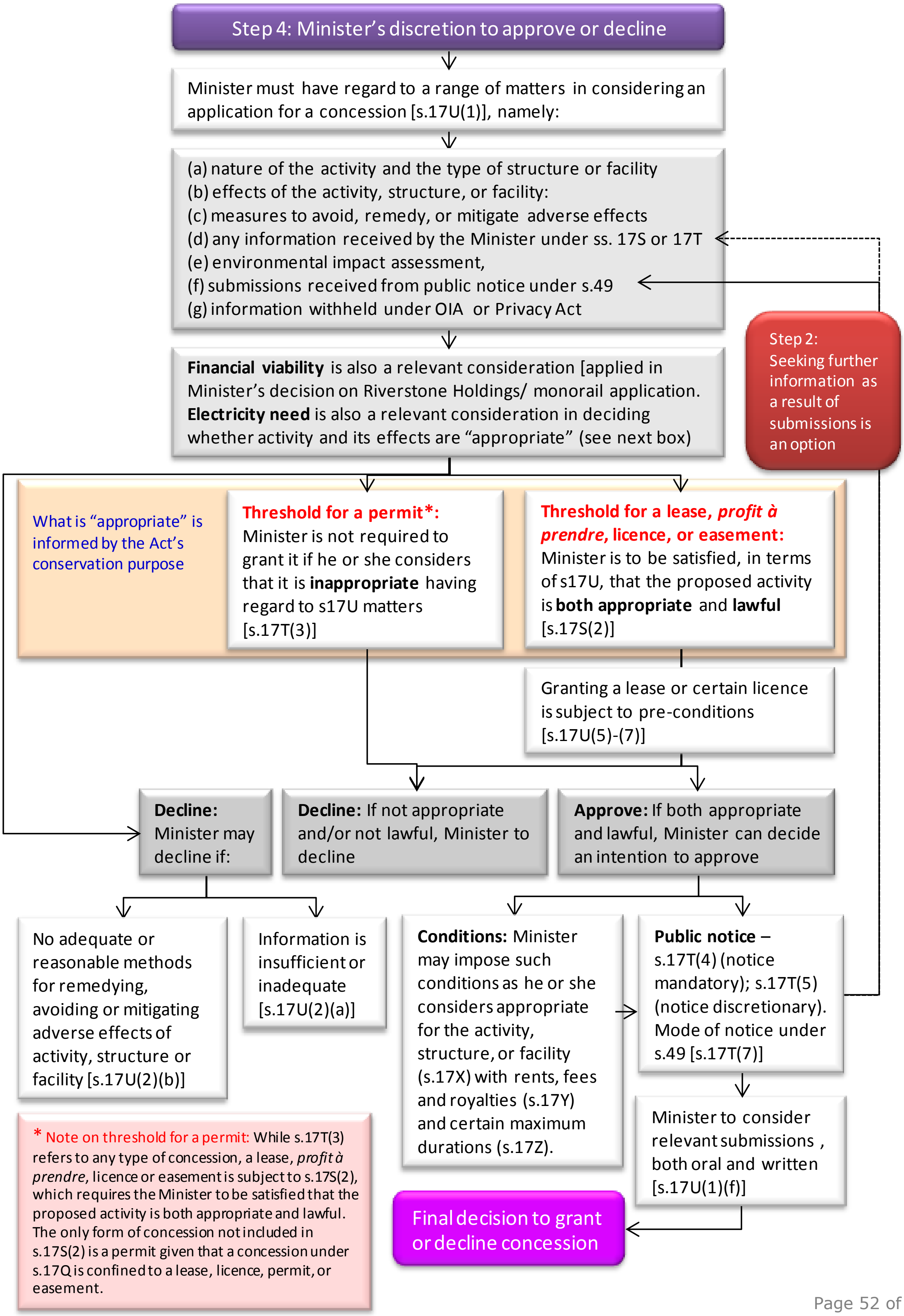


Figure 5: Minister's discretion to approve or decline.

To approve a lease, licence or easement, the Minister must be satisfied, in terms of s17U, that it is both appropriate and lawful. "Appropriate" is a higher threshold than simply "lawful". What is "appropriate" is informed by the Act's conservation purpose.



3. Westpower and its network

3.1 Outline of this section

Before assessing the need for and viability of the proposed Waitaha scheme, it is important to understand Westpower, its history, currents business, main drivers, and its strategy for the future. This section 3 is divided into the following parts:

- Outline of this section
- Summary of key points
- Historical ownership of generation and electricity retailing
- Westpower's strategy
- Westpower's key financials
  - Sources of revenue
  - Profit and other revenue markers
  - Other key financials
- Westpower's current structure and activities
  - West Coast Electric Power Trust
  - Electronet
  - Mitton and ABB businesses
  - Amethyst hydro – Westpower does not retail
- Westpower's relative size
- Consumers on Westpower's network
- Westpower's network
- Maximum demand
- Losses and location factors
  - Transmission losses
  - Incorrect claims about losses
  - Distribution losses
  - Explanation of electricity losses
- Governance and regulation
- Further information

3.2 Key points

- Westpower was displeased at having to sell its portfolio of generation assets in 1998/99. It clearly wants to re-establish a generation business.

- While the business of electricity distribution tends to relatively low growth, it is apparent that Westpower wants to grow. This is evident from its history of electricity demand forecasting (reviewed in section 6 of this report), its investment in electrical engineering and electricity transmission service businesses, and its initiatives to invest in new generation projects.

- Westpower's revenues from sources other than its monopoly local lines business (and excluding related party transactions) now account for approximately [%] of its total revenues. From 2006 to 2014, total assets grew 94%, total equity increased 64%, and gearing increased from 21% to 33%.

- Westpower services a small population relying on a relatively limited range of economic activity – mainly mining, dairying and tourism. It supplies about 13,000 consumers. By number, 93.5% of Westpower's connections are small consumers. Larger consumer connections total around 25 in number and this has been reasonably steady for the last three years. There were just two electricity users in Westpower's region consuming more than 5 MW of electricity.

- Westpower's network covers a large geographical area with challenging terrain and extreme weather conditions. Its electricity distribution network comprises about 2,252 kilometres of power lines covering a region from Lyell in the North to Paringa in South Westland, an area of about 18,017 square kilometres.

- For the year ended 31 March 2014, the 'maximum coincident system demand' on Westpower's network was 48 MW. This is a significant decline on its 2011 peak of 55 MW, which was followed by consecutive falls in 2012, 2013, and 2014. On average, around 8.5% to 13% of electricity is lost in transporting electricity to Westpower's network using Benmore as the reference point.

- Westpower is one of the smallest electricity distribution businesses in New Zealand. Combined with Buller Electricity, it represents around 0.6% of total electricity connections in New Zealand, 0.9% of total energy delivered in New Zealand, and 1.4% of total system length in New Zealand

3.3 Historical ownership of generation and electricity retailing

Until 1999, Westpower owned local hydro generation, in particular Kumara-Dillmans-Duffers, Arnold, Kaniere Forks, Mackay Creek, Wahapo, Fox Glacier and the Turnbull power schemes.

In 1998/99, these and its electricity retail business were sold to comply with the Electricity Industry Reform Act 1998, which prohibited electricity lines companies from owning generation or retailing. Westpower's hydro schemes were purchased by Trustpower.[43]

It is reasonable to surmise that Westpower was displeased at this forced divestment. In its Waitaha application, Westpower emphasises that:

[43] Westpower's application to the Commerce Commission in relation to the Amethyst hydro proposal, August 2006, at para 19

> "In the early 1990's the government required the community to divest itself of generation assets which then came under the control of national generators. This essentially disabled the ability for the local community to provide for itself, and plan for the future, in a self-sufficient manner." [44] [Note – it was 1998/99, not "the early 1990s]

These notions of "self sufficiency" and "community ownership" in electricity generation are offered by Westpower as key justifications for the Waitaha proposal. This is discussed further in section 12 of this report.

3.4 Westpower's strategy

The primary focus of a local electricity lines business is security, reliability and efficiency. It is a relatively low growth business, particularly if demand for electricity is reasonably flat, as it is for Westpower on a medium term outlook. It is much more about controlling costs and improving efficiency than revenue and asset growth. This can be limiting for managers and directors keen to see their business grow.

However, it is apparent that Westpower has a strategy of growth. This is evident from its history of electricity demand forecasting (reviewed in section 6 of this report), its investment in electrical engineering and electricity transmission service businesses, and its initiatives to invest in new generation projects.

Westpower's growth objective is set out in its Statement of Corporate Intent 2015-2017:

> "Westpower's Directors have established a strategic direction which includes growing the wider business, while ensuring that the core business of electricity distribution is sustained."

Following the relaxation in 2001 and 2004 of statutory restrictions on electricity distribution businesses owning (or being involved with) electricity generation and retailing,[45] Westpower decided to "re-enter electricity generation" on the grounds that it had considerable management expertise and experience in hydro generation.[46] It also considered distributed generation to be "the most effective and secure way of meeting growing demand for electricity in the South Island".[47]

Since at least 203, Westpower has been developing new hydro generation projects. Key milestones made public by Westpower include:

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[44] Westpower's Waitaha application, Appendix 22, page 2

[45] Restrictions on electricity distribution businesses owning (or being involved with) electricity generation and retailing were further substantially lessened by legislative changes in 2008 and 2010. Restrictions were lowered by 2001, 2004 and 2008 amendments to the Electricity Industry Reform Act 1998, and the Electricity Industry Act 2010

[46] Westpower's application to the Commerce Commission in relation to the Amethyst hydro proposal, August 2006, at para 20

[47] Westpower's application to the Commerce Commission in relation to the Amethyst hydro proposal, August 2006 , at para 21

Table 1: Public milestones in Westpower's generation developments

	Amethyst scheme	Waitaha scheme
2003	Environmental impact assessment report	
2004	Westpower says it was invited to join Amethyst project in 2004	Westpower undertook a survey of various rivers
2005		Scoping study by S Matheson. Civil pre-feasibility study by Matheson and McCahon. Pre-feasibility environment risk assessment.
2006	Final feasibility and design. Application to Commerce Commission	Hydrological monitoring
2007		Westpower announces intention to proceed
2008	Minister grants concessions	
2009		Put on hold to focus on the construction of Amethyst scheme
2010	Tunnel construction underway	
2011	Transpower's major West Coast transmission upgrade commissioned. West Coast demand declines significantly (YE 31 March 2011 – 14)	
2012		Westpower announces intention to proceed. Consultant reports
2013	Amethyst scheme commissioned	Consultant reports
2014		Westpower applies to Minister/DOC for concessions

This chronology is shown relative to electricity demand in section 6 of this report.

More recently, "self-sufficiency" in electricity supply for the West Coast has become is a key plank in Westpower's presentation of its business strategy:

> "Westpower's return to hydro-development is part of reinvigorating the generating capabilities of the West Coast community, both current and future generations, and is aimed at regaining a level of local self-sufficiency in generation and supply based on a local and renewable hydro resource."[48]

This is discussed further in section 12 of this report.

[48] Westpower's Waitaha application, Appendix 22, page 2

Westpower's growth strategy is also reflected in its 2007 purchase of Mitton Consultants, an electrical engineering services company, and its 2008 purchase of ABB's transmission lines maintenance and build services.

As shown in Figure6 and 8 below, Westpower's revenues from sources other than its monopoly local lines business (and excluding related party transactions) now account for approximately 60% of its total revenues.

3.5 Westpower's key financials

3.5.1 Sources of revenue

As shown in Figure 6, Westpower Group has three sources of revenue:

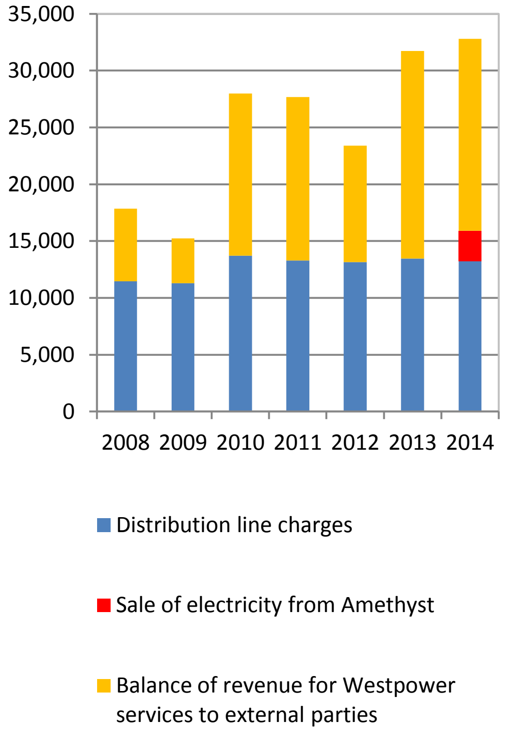
- Charges for use of its network (blue columns);
- Charges for contracting and consulting services to third parties (orange columns); and
- Since June 2013, sales of electricity from its Amethyst hydro generation (red columns).

These elements are outlined further below.

In addition, Westpower receives payments that it must pass on to other parties – for example, transmission charges (which it pays to Transpower) and payments for 'avoided transmission costs' (which it pays to local generators, mainly Trustpower). These amounts appear as income in Westpower's financial statements, however they are simply 'passed through'.

Westpower also pays Electronet for asset management services that Electronet provides to Westpower. While this appears as revenue in Westpower's financial statements, it is simply a transfer payment or 'related party transaction'.

Figure 6 : Westpower's three sources of revenue.
(Excludes transfers and pass-throughs. Years in the chart are for the financial year ended 31 March)



The orange column in Figure 6 above shows the balance of Westpower's revenue after deducting lines charges, sales from generation, pass-throughs, transfer payments, capital contributions, vested assets and AC loss rebates. By deduction, this would seem to represent the revenue Electronet earns for contracting and consulting services to third parties.[49]

[49] The amount is not separately identified in Westpower's financial statements but it can be derived approximately

Net of the pass-throughs and transfers[50], Westpower seems to have had a gross income in for the year ended 31 March 2014 of around $33m made up of:

• Distribution line revenue	$13.2m
• Sale of electricity from generation	$2.7m
• Balance of revenue (probably mainly from Electronet services to third parties)	$16.9m
	$32.8m

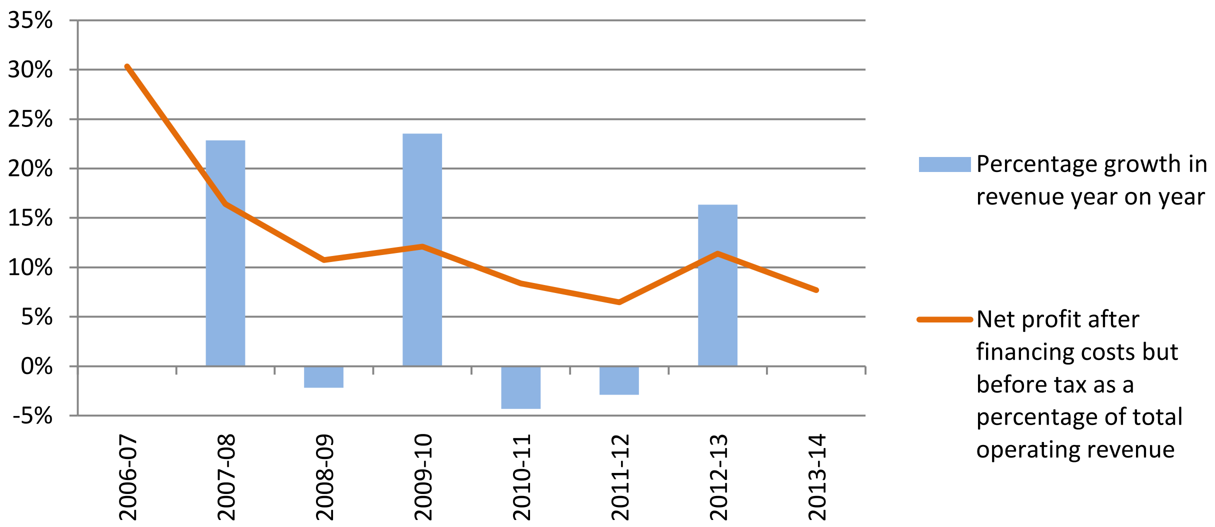
Presumably, the $2.7m above for electricity sales from generation represents about eight months of output from Amethyst as it was commissioned in June 2013. If so, the contribution from Amethyst is likely to be higher in 2014/15 reflecting a full year of electricity sales.

The composition of Westpower Group's income and expenditure is set out in more detail in Figure 8 below. This chart illustrates various component amounts, including related party transactions between Westpower and Electronet; pass-through payments from Westpower to Transpower for transmission charges, and from Westpower to local generators for avoided transmission costs; discretionary discounts on distribution line charges; and net financing costs, total expenditure, profit, and total regulatory income (which is covered by the Commerce Commission).

3.5.2 Profit and other revenue markers

From 2007 to 2014, Westpower's total operating revenue grew 60%. However, in the same period, profit after financing costs but before tax relative to total operating revenue has decline significantly from 30.3% to 7.7%.

Figure 7: Change in profit and revenue
Source: Westpower Information Disclosure and Financial Statements (year ended 31 March)



[50] And capital contributions, vested assets and AC loss rebates

3.5.3 Other key financials

From 2006 to 2014, total assets grew 94%, total equity increased 64%, and gearing increased from 21% to 33%. Operating liquidity deteriorated sharply from 2009 to 2013, presumably when short term borrowings increased to fund the building of the Amethyst scheme. The financials are shown in Figure 9 below.

Go to next page

Figure 8: Westpower's income and expenditure for year ended 31 March 2007 – 2014:

Sources: Westpower's statutory Information Disclosure and Annual Reports

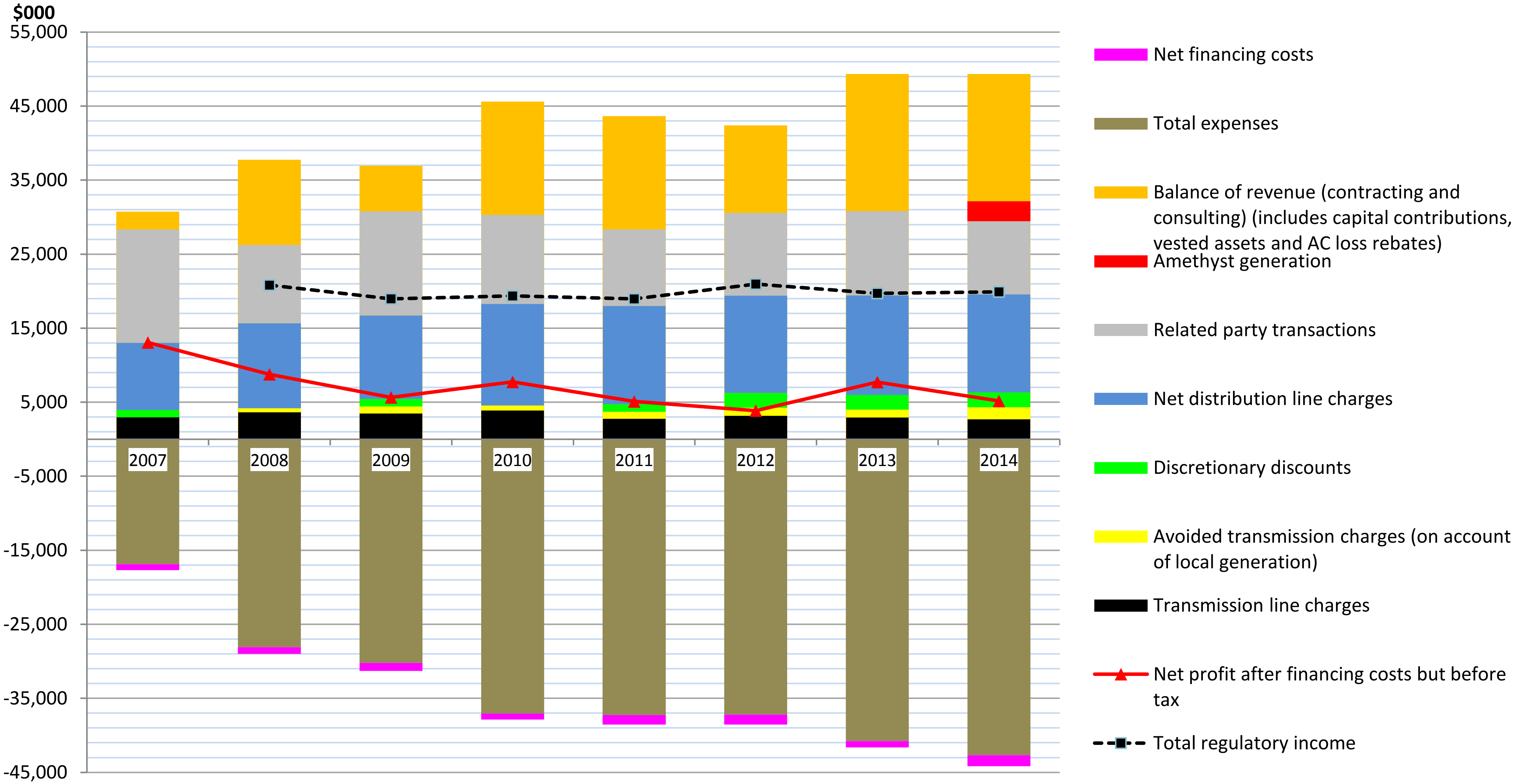
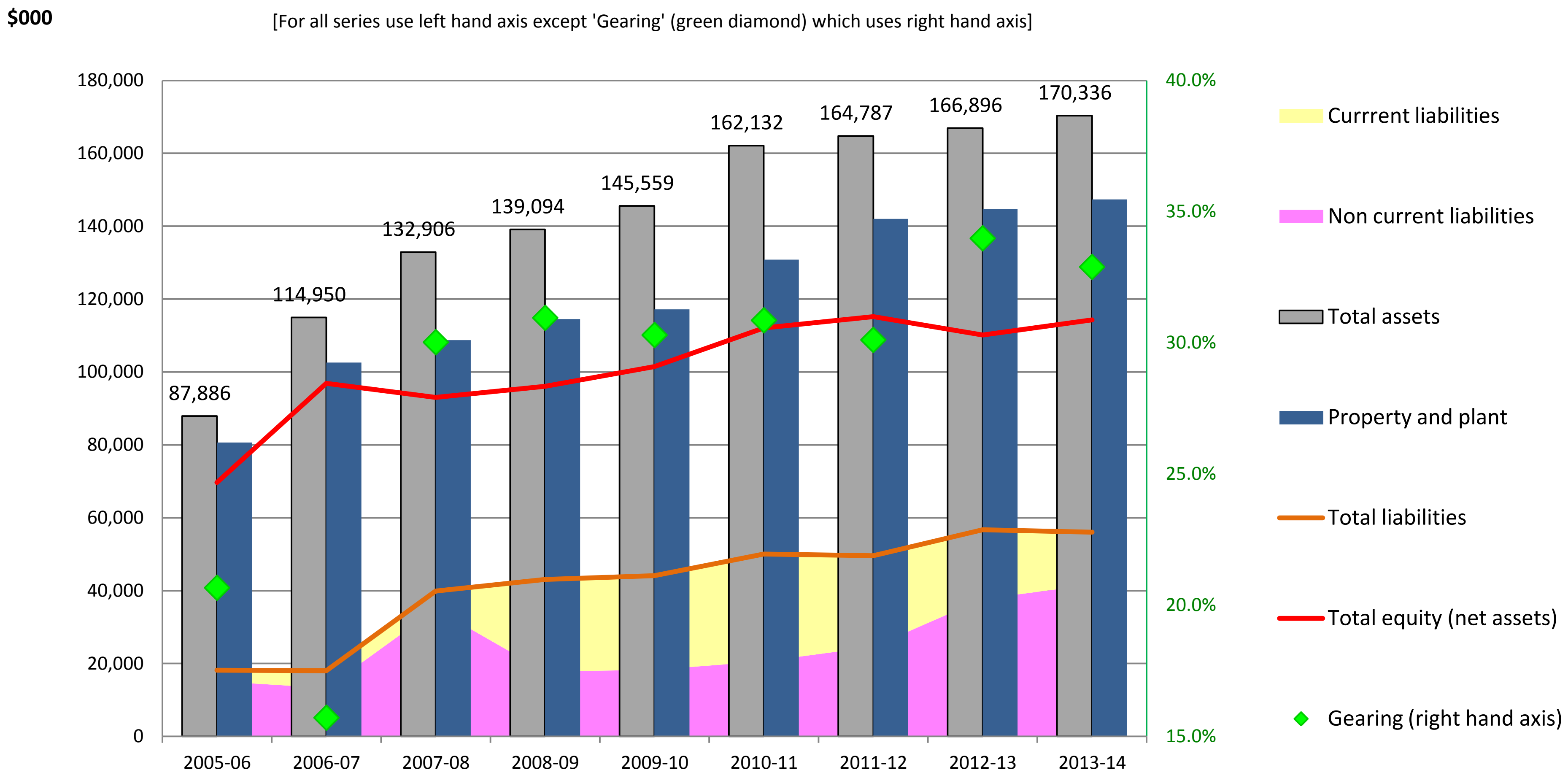


Figure 9: Key financials

Source: Westpower's Information Disclosure and Financial Statements (year ended 31 March)



3.6 Westpower's current structure and activities[51]

3.6.1 West Coast Electric Power Trust

Westpower Limited ('Westpower') owns and operates the electricity distribution network on the West Coast of the South Island[52]. The company is owned by the West Coast Electric Power Trust on behalf of West Coast electricity consumers.

3.6.2 Electronet

Westpower owns 100% of ElectroNet Services Limited, which is contracted by Westpower to operate and maintain Westpower's network. This includes inspection, servicing and testing, fault callout and fault repair work, and major line replacement, enhancement or development projects[53]. Electronet Services also provides transmission and electrical contracting services to other parties. It is reported that, apart from Westpower's Chief Executive and Asset Manager, who all work directly for Westpower, all of Westpower's people are employed by Electronet Services.[54]

3.6.3 Mitton and ABB businesses

ElectroNet Services owns two subsidiaries:

- Mitton ElectroNet Limited, a Christchurch-based electrical engineering services company formed in 2007 following ElectroNet's acquisition of Mitton Consultants Ltd; and

- ElectroNet Transmission Limited, a Nelson and Greymouth based company formed in 2008 following ElectroNet Services' acquisition of ABB's lines maintenance business. It provides electricity transmission, maintenance and build services on the West Coast and Nelson/Marlborough regions.

3.6.4 Amethyst hydro – Westpower does not retail

Westpower also has an 88% share in Amethyst Hydro Limited, which is a joint venture company with Harihari Hydro Limited (12% share[55]) that owns the 7 MW hydro scheme on the Amethyst Ravine near Harihari commissioned in June 2013.

It is important to note that Westpower does not sell electricity to consumers. Westpower simply delivers electricity from the transmission grid and local generation to consumers. The electricity is sold by competing electricity retailers.

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[51] Information below has been sourced from Westpower's Asset Management Plan 2014-24 and http://www.westpower.co.nz/our-business and http://www.westpower.co.nz/company-structure

[52] Westpower is a combination of a number of the early power companies and generators on the West Coast. In 1972, the West Coast Electric Power Board was formed by the amalgamation of the Amethyst, Grey and Westland Electric Power Boards – see Westpower's Asset Management Plan 2014-2014, section 2.2.1

[53] In short, Electronet Services carries out the asset management function for Westpower – see Westpower's Asset Management Plan 2014-24, section 2.1.4.

[54] Westpower's application to the Commerce Commission in relation to the Amethyst hydro proposal, August 2006, at para 11

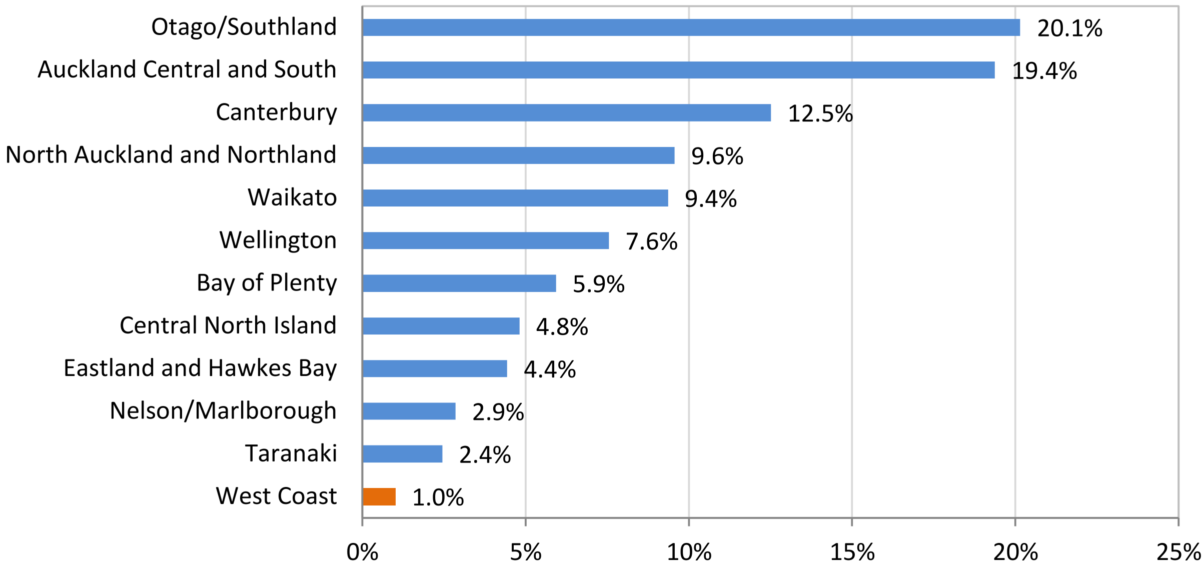
[55] This 12% share is held 50/50 by Martin Christopher Doyle and Robert Allan Smith – http://www.business.govt.nz/companies/app/ui/pages/companies/1539938/detail

Electricity from Westpower's Amethyst hydro scheme is reportedly sold to Trustpower under an off-take agreement.

3.7 Westpower's relative size

As shown in Figure 107 below, Westpower's share of New Zealand's electricity distribution industry is comparatively small. Combined with Buller Electricity, it represents around 0.6% of total electricity connections in New Zealand, 0.9% of total energy delivered in New Zealand, and 1.4% of total system length in New Zealand[56].

Figure 10: Approximate Share of National Demand by Region for the 2013 year.
Source: Electricity Authority - http://www.emi.ea.govt.nz/



3.8 Consumers on Westpower's network

By number, 93.5% of Westpower's connections are small consumers – that is, 12,315 small connections out of 13,170 connections in total.[57] The number of medium consumer connections has declined slightly from 845 (in 2010) to 830 (in 2014). Larger consumer connections total around 25 in number and this has been reasonably steady for the last three years.

[56] Commerce Commission's report on Westpower's performance, 2008–2011:

http://www.comcom.govt.nz/regulated-industries/electricity/electricity-distributors-performance-from-2008-to-2011/edb-performance-westpower/

[57] Westpower's 2014 Information Disclosure under the Commerce Act for year end 31 March 2014, Schedule 12c - http://www.westpower.co.nz/information-disclosures

As at 31 March 2014, the eight largest electricity users accounted for about 40% of total electricity consumption on Westpower's network. Between 2008 and 2011, the top five largest users accounted for 45% of total consumption, however, in the same period, Westpower's large customer connections declined in number by 15%.[58]

Despite larger users consuming around 40% of total electricity on the network, those larger users only contribute around 21% of Westpower's revenues from lines charges (including transmission payments).

As at 31 March 2014, there were just two electricity users in Westpower's region consuming more than 5 MW of electricity – Oceana Gold and Westland Milk Products . Only another five consumed more than 1 MW – Solid Energy (Spring Creek mine), Roa coal mine, Stillwater Sawmill, Phoenix meat works and Westfleet fish processing. The larger electricity consumers on Westpower's network are set out in the following table.

This concentration of consumption highlights Westpower's exposure to changes in electricity demand by its small number of larger customers. This exposure has been particularly evident during the last four years with the closure of Pike River mine (2010), Solid Energy's decision to suspend all the work at its Spring Creek mine (2012), and Oceana Gold's announcement (2013) that its open pit at Reefton is to be mothballed by mid-2015. Westpower's planning is also significantly exposed to international dairy prices over time.

Table 2: Westpower's larger electricity consumers.
Source: Westpower's Asset Management Plan 2014-2024, section 3.14

	kW	kW
Reefton sub-network:		
Terrace Mine - underground coal mine	75	
Oceana Gold Limited - open cast gold mine	5,300	
Subtotal - Reefton		5,375
Atarau sub-network:		
Pike River coal mine (closed)		
Subtotal -Atarau		
Dobson sub-network:		
Solid Energy - Spring Creek - underground coal mine	1,000	
Roa Coal Mine - Blackball - underground coal mine	1,200	
Stillwater Lumber - timber mill	1,200	
CMP - Phoenix Meat Works, Kokiri abattoir	1,360	
Subtotal - Dobson		4,760

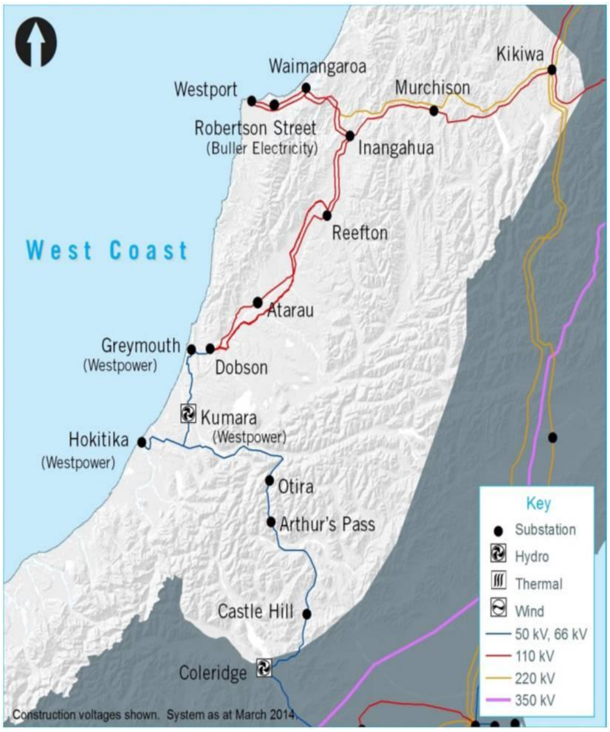
[58] Commerce Commission's Review of Westpower's performance, 2008-2011 http://www.comcom.govt.nz/regulated-industries/electricity/electricity-distributors-performance-from-2008-to-2011/edb-performance-westpower/

	kW	kW
Greymouth sub-network:		
Kingsgate - Greymouth hotel	300	
Westfleet - Greymouth fish processing plant	1,000	
Fresh Choice - Greymouth supermarket	220	
Monteiths Brewery - Greymouth brewery	200	
New World - Greymouth supermarket	310	
The Warehouse - Greymouth retail store	200	
Coast Health - Greymouth hospital	410	
IPL - Plywood - Gladstone timber processor	650	
Subtotal - Greymouth		3,290
Kumara sub-network:		
IPL - Plywood Mill - Gladstone timber processor	550	
Subtotal - Kumara		550
Otira sub-network:		
Tranz Rail - Otira fan load	600	
Subtotal - Otira		600
Hokitika sub-network:		
Westland Dairy - Hokitika dairy factory	8,200	
Westco Lagan - Ruatapu sawmill	880	
Silver Fern Farms - Hokitika venison factory	250	
New World - Hokitika supermarket	200	
Westland Motor Inn - Franz Josef hotel	180	
Subtotal - Hokitika		9,710
Total (in kilowatts)		**24,285**
Total (in megawatts)		**24.3**

3.7 Westpower's network[59]

Westpower's network covers a large geographical area with challenging terrain and extreme weather conditions. It services a small population relying on a relatively limited range of economic activity – mainly mining, dairying and tourism.

[59] Information is about Westpower's network is drawn from its Asset Management Plan 2014-24, section 2.1.4. Also Transpower's Annual Planning Report, March 2014 (see section 16, page 239 on West Coast)



Source: Transpower

Westpower supplies about 13,000 consumers. Its electricity distribution network comprises about 2,252 kilometres of power lines covering a region from Lyell in the North to Paringa in South Westland, an area of about 18,017 square kilometres[60].

As Transpower notes[61], the West Coast load is mostly supplied from the northern infeed, with power flowing through the region via the 110 kV circuits from Kikiwa to Dobson via Inangahua. As noted in section 6 of this report, the transmission service feeding Westpower's network was substantially upgraded in 2011. Buller Electricity's network is supplied via the 110 kV spur from Inangahua to Robertson Street and Westport.

Some loads are fed from the south via low capacity double-circuits 66 kV from Coleridge, which also provide significant voltage support to the region.[62] This is supported by a limited capacity 66 kV connection between Dobson and Kumara.

Westpower receives electricity from these transmission feeds at seven grid exit points (at 110 kV, 66 kV, 33 kV and 11 kV). The capacity of Westpower's substations is outlined later in this report.[63]

3.9 Maximum demand

For the year ended 31 March 2014, the 'maximum coincident system demand' on Westpower's network was 48 MW. This is set out in Westpower's 2014 Information Disclosure to the Commerce Commission.

By contrast, Westpower's 2014–2024 Asset Management Plan states that its current total load for 2013 was around 50.5 MW with forecast a total (maximum) demand for 2014 of 55 MW[64].

[60] Westpower's Asset Management Plan 2014-24, Figure 3.1 at page 64

[61] Transpower's 2014 Annual Planning Report, section 16.2.2, page 241

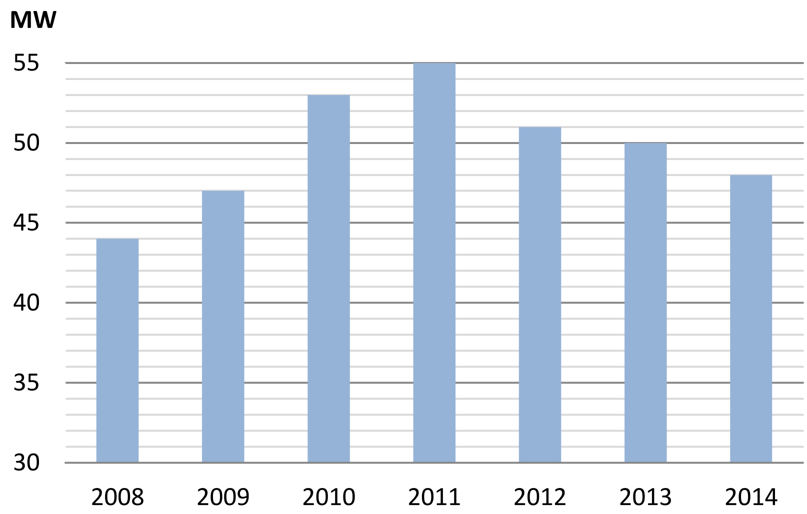
[62] Transpower's 2014 Annual Planning Report, section 16.2.2, page 241, and section 3.2, page 66

[63] Westpower's Asset Management Plan 2014-24, sections 2.1.4 and 3.2 , and Table 3.1

[64] Westpower's Asset Management Plan 2014-2024 at 2.1.5 on page 27 and Figure 5.2 on page 133 respectively

From Westpower's Information Disclosures to the Commerce Commission, maximum demand over the last seven years is shown as follows.

Figure 11: Maximum coincident system demand on Westpower's network.
Source: Westpower's Information Disclosure
Years in the chart are for the financial year ended 31 March



3.10 Losses and location factors

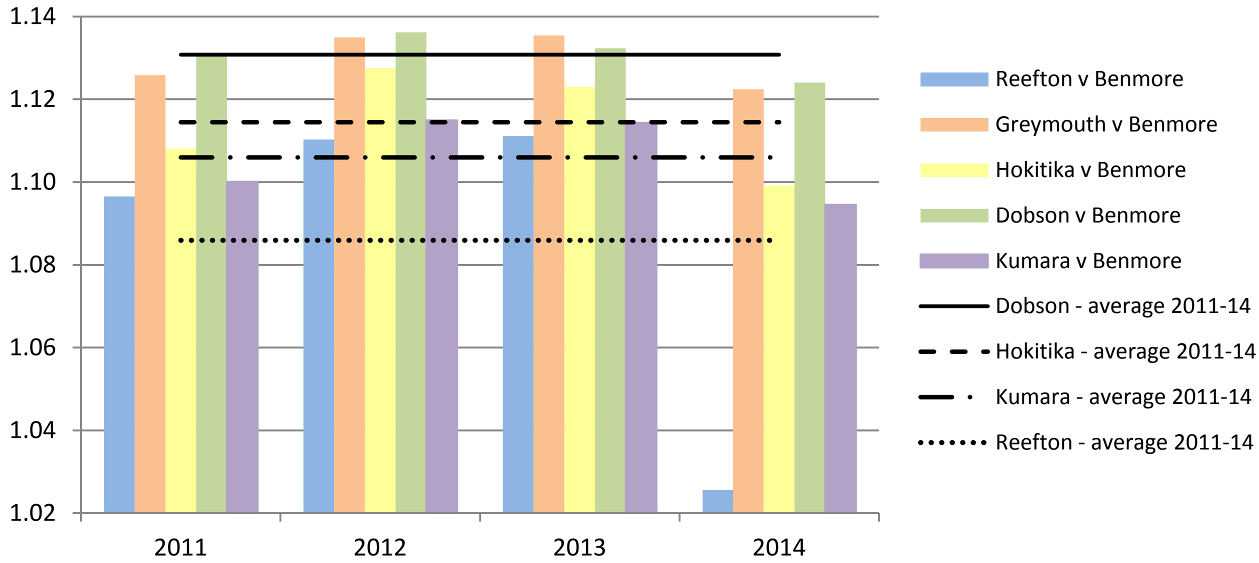
3.10.1 Transmission losses

On average, around **8.5% to 13%** of electricity is lost in transporting electricity to Westpower's network using Benmore as the reference point.[65]

The annual average location factors for 2011 to 2014 at Westpower's five main grid exit points using Benmore as the reference node are shown in the below. These location factors range from an annual average low of **1.025** (at Reefton, 2014) to an annual average high of **1.136** (at Dobson, 2012). The average for 2011 to 2014 ranges from 1.085 to 1.130.

[65] The Benmore node is the location on the national grid at which Benmore power station injects electricity. Benmore is the southern end of the HVDC link, and if there are no significant intra-island constraints then half-hourly prices at the Benmore node generally reflect the half-hourly prices across the South Island. Benmore is one of the three key reference nodes, along with Haywards and Otahuhu. Source: 2009 Ministerial Review, Volume 2, Appendix 1

Figure 12: Location factors at Westpower's main grid exit points.
Source: Electricity Authority for actual prices.
Years in the chart are for the financial year ended 31 March



3.10.2 Incorrect claims about losses

Transmission losses into Westpower's network have been greatly exaggerated over the years and become key plank in the case for Westpower becoming "self sufficient" in electricity generation.

For example, in 2009 West Coast Regional Council chief executive, Chris Ingle, asserted:

> "We don't want to rely on the Waitaki scheme and lose **50%** of the energy on the way over".[66] [Emphasis added]

In its Waitaha application, Westpower asserts at page 8:

> "The current electricity supply relies on the importation of electricity over long distance transmission lines. Transmission losses approaching up to **20%** occur as a result of power being imported from outside the West Coast. This results in costs to the wider community in terms of energy loss as well as to the local West Coast community in terms of financial costs". [Emphasis added]

The days of average transmission losses of 20% are from a different era. In 2005, the average location factor at Dobson was 1.215 – that is to say, 21.5% of electricity was lost between Benmore and Dobson.[67]

[66] The Press, 17 July 2009 - http://www.stuff.co.nz/the-press/news/2601161/Council-thinks-big-on-hydro-power-projects

[67] Assuming no constraints

However, as outlined above, this reduced significantly from 2011 following the major upgrade of transmission services into Westpower's network. In 2014, transmission losses at Westpower's Dobson node were **12.4%** losses[68] – an improvement of 9.1% percentage points relative to the 21.5% high in 2005. Much of this improvement is due the transmission upgrade.

3.10.3 Westpower relative to New Zealand average

Transmission losses in supply Westpower's network are high relative to the New Zealand average.[69] Across New Zealand as a whole, transmission losses from 2009 to 2013 averaged 4.83% per year.[70]

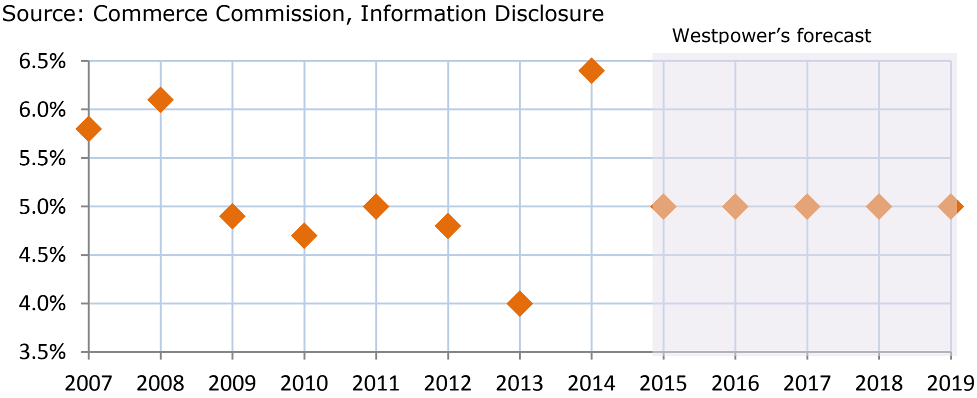
In 2012, the electricity loss ratio across the New Zealand electricity system as a whole was 7%: electricity lost on distribution lines was 5.2%, and electricity lost in transmission was 4.3% [MBIE electricity data]

This reflects the relatively long distance of transmissions lines into the West Coast. As explained in the side box below, the greater the distance the electricity travels and the lower the voltage of the line, the higher the losses.

3.10.4 Distribution losses

The percentage of electricity lost on Westpower's network is approximately 5%. The actual losses since 2007 are set shown in the chart below.

Figure 13: Electricity losses on Westpower's network.
Source: Commerce Commission, Information Disclosure



In 2012, Westpower ranked 21st in New Zealand for losses on a distribution network. Across New Zealand as a whole, distribution losses from 2009 to 2013 averaged 6%% per year.[71]

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[68] Assuming no constraints

[69] For the period 1 February 2015 to 31 January 2016, four of Westpower's grid exit points are among the top 20 in New Zealand with the highest losses and constraints as ranked by the location factors set by the Electricity Authority for the NZ hedge market.

[70] MBIE electricity data

[71] MBIE electricity data

3.10.5 Explanation of electricity losses

The side box below explains why electricity losses occur and why they are relevant to wholesale electricity pricing.

> As it travels along transmission and distribution networks, electricity is lost as heat due to resistance in the lines.[72] The greater the distance the electricity travels and the lower the voltage of the line, the higher the losses. [73] Losses, combined with any constraints on the flow of electricity along the transmission lines, are real costs, which are reflected in the wholesale price of electricity.
>
> The price is usually higher at the point where electricity exits the transmission grid compared to the price at the point where it was injected into the grid. In the New Zealand system, the purchaser (the retailer or wholesale buyer) pays the price at the exit point, not the injection point.[74]
>
> The ratio of the price at the grid exit point relative to the price at the injection point is called the 'location factor'. In the absence of transmission constraints, the location factor expresses the percentage of actual losses of electricity incurred in transporting it on the grid from its injection point to its exit point.

3.11 Governance and regulation[75]

Westpower was formed under the Energy Companies Act 1992, which (among other things) makes Westpower subject to the Companies Act 1993. Under section 36 of that Act, Westpower's principal objective is to operate as a successful business. In seeking to attain that objective, it is to have regard, among other things, to the desirability of ensuring the efficient use of energy.

In accordance with Section 39 of the Energy Companies Act 1992, the Board is to submit to the Marlborough Electric Power Trust a draft Statement of Corporate Intent (SCI) for the coming financial year. The SCI is to set out the company's overall objectives, intentions and financial performance targets.

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[72] These losses are known as ohmic losses, which are proportional to the square of the current in the wires. Most of the energy losses in alternating current electric power grids are due to the resistance of conductors to the circulation of electric current flows. Losses also depend on voltage and the impact of transformers, reactors and capacitors – "Transmission Pricing", 2013, Ignacio J. Pe´rez-Arriaga, Luis Olmos, and Michel Rivier – http://www.springer.com/cda/content/document/cda_downloaddocument/9781447147862-c1.pdf?SGWID=0-0-45-1379006-p174690243

[73] 2009 Ministerial Review, Volume 2, page 8, Definition of Losses

[74] The New Zealand electricity system uses 'nodal pricing', the concept of which is that the price at a particular node represents the marginal cost of supplying electricity at that node (including the cost associated with losses and constraints on the transmission grid). In New Zealand the nodal price is calculated for approximately 244 market nodes, in addition to over 200 transfer nodes.

[75] Information under this heading is drawn from the Commerce Commission – "Factsheet on Default Price Quality Path For Electricity Distributors", July 2014 - http://www.comcom.govt.nz/regulated-industries/electricity/electricity-default-price-quality-path/default-price-quality-path-from-2015/fact-sheet-draft-default-price-quality-path-for-electricity-distributors/ and http://www.comcom.govt.nz/regulated-industries/electricity/electricity-default-price-quality-path/

Westpower is subject to information disclosure regulation under subpart 9 of Part 4 of the Commerce Act 1986. Because it is small and owned by a consumer trust,[76] Westpower is not subject to price-quality regulation.

However, the information disclosure regime demarcates the components of Westpower's business that form part of its electricity distribution service, and monitors the performance of those components against key parameters. The disclosure regime is intended to enable the Commerce Commission and other interested parties to gauge whether Westpower costs and/or profits are too high or its service quality is too low. If these metrics are out-of-line, the regime contemplates that pressure would be applied by the Commerce Commission and other interested parties on Westpower to make appropriate adjustments. In this sense, regulation of prices and service quality is implicit.

By contrast, other electricity distribution businesses in the South Island – Network Tasman (which is also owned by a consumer trust), Orion and Aurora Energy – are under direct price-quality regulation. The prices path authorised by the Commerce Commission for distribution businesses will not necessarily keep rising.

The current price-quality regulations took effect on 1 April 2009 following the passing of the Commerce Amendment Act in November 2008. Prior to this date, all electricity distribution businesses were subject to the Part 4A thresholds regime, which was established in 2001.

3.12 Further information

Further information relating to supply and demand (both historical and forecast) on Westpower's network is outlined in sections 6 and 9 of this report.

[76] The criteria for the 'consumer-owned' exemption are set out in s 54D of the Commerce Act

4. Waitaha scheme

4.1 Outline of this section

This section is divided into the following parts:

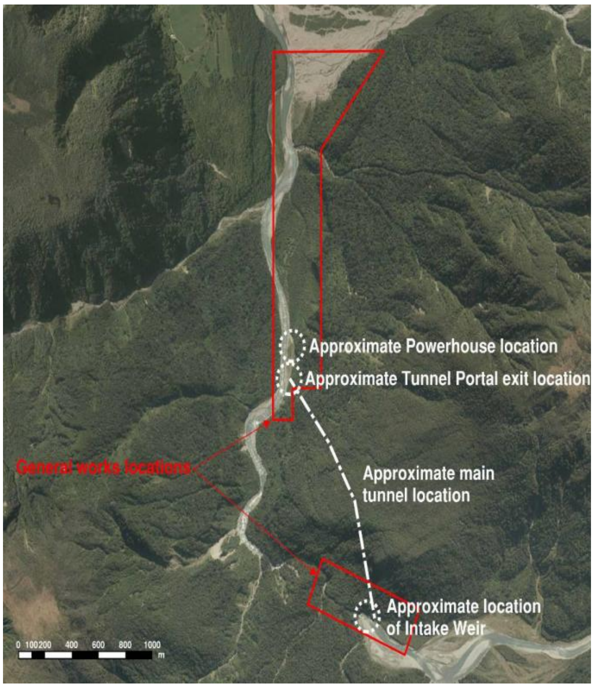
- Summary of key points
- Essence of scheme
- Amethyst precedent
- Upper Waitaha catchment
    - Geography
    - Conservation values and adverse effects
- Need for sub-transmission upgrade
- Electricity sold to an unrelated electricity retailer
- Exporting Waitaha electricity
- Summary of key engineering features

4.2 Summary of key points

The key points set out in the executive summary at section 1.7 of this report.

4.3 Essence of scheme

Figure 14: Proposed scheme layout:
Source: Waitaha application



Westpower proposes to build, own and operate a hydro scheme within the Upper Waitaha catchment of the Waitaha Valley, which is about 38 km south of Hokitika.

In essence, the scheme would take and divert up to 23 cumecs of water from the Waitaha River leaving a residual 3.5 cumecs to flow into Morgan Gorge.

Water would be diverted by a weir and diversion structure at the bottom of Kiwi Flat, flow into an intake structure, down a 1.5 kilometre tunnel, through penstocks, into a powerhouse and switchyard located below the Morgan Gorge, and then, via a tail-race structure, back into the natural flow of the Waitaha River approximately 2.6km downstream of the intake.

It would be a run-of-river scheme with no ability to store water. The scheme is intended to produce 110 – 120 GWh per year with a peak output of 16 – 20 MW[77].

The proposed scheme is primarily located, within stewardship conservation land managed by the Department of Conservation. A small area of the scheme is located within private land, immediately north of the stewardship land.[78]

The scheme would also require a 10 m wide access road extending from the farmed Waitaha Valley to the powerhouse.

The scheme is described in general terms in Westpower's brochure of September 2013[79], and in more detail in Westpower's application to the Minister of Conservation for concessions of July 2014.[80]

4.4 Amethyst precedent

Westpower presents the Waitaha scheme as very similar to the Amethyst scheme[81], which is described later in this report:

> "The Amethyst Hydro Scheme has a very small footprint and illustrates how significant advantages can accrue to the local community through small scale run-of-river hydro development. Westpower is committed to quality developments and sound environmental practices and expects to apply the same key success factors to the Waitaha Hydro Scheme."

In June 2012, Westpower stated that the Waitaha scheme that "would be another small scale run of the river scheme, similar in construction to the Amethyst one"[82]. References to Waitaha's claimed likeness to the Amethyst scheme are made in various parts of Westpower's Waitaha application.

4.5 Upper Waitaha catchment

4.5.1 Geography

The Waitaha River reaches from the West Coast to the Main Divide, with a total catchment area of 223 km^2. The Scheme is situated in the upper half of the catchment and utilises water

[77]Westpower: Waitaha Hydro Scheme Application for Concessions and Assessment of Environmental Effects – July 2014, and Q&A on Westpower's web site - http://www.westpower.co.nz/news/article/questions-and-answers-waitaha-hydro

[78] Westpower's Waitaha application, Appendix 9 – "Waitaha Hydro Scheme Natural Character, Landscape and Visual Amenity Effects", 24 March 2014, Boffa Miskell

[79] Westpower's brochure http://www.westpower.co.nz/sites/default/files/Brochure%20-%20Proposed%20Waitaha%20Hydro%20Scheme%20September%202013_0.pdf

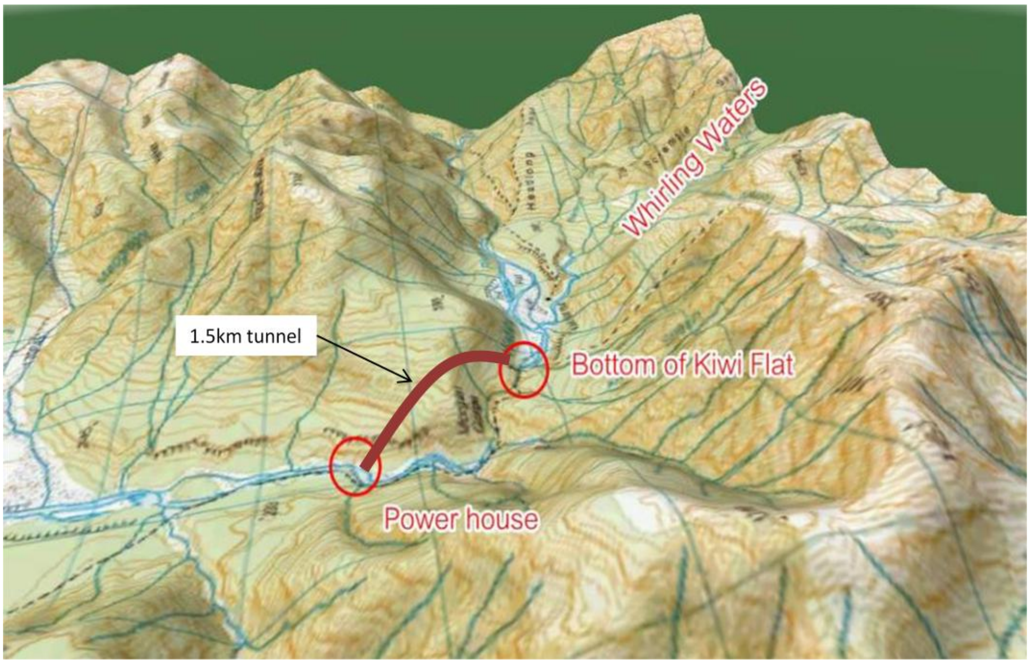
[80] Westpower: Waitaha Hydro Scheme Application for Concessions and Assessment of Environmental Effects – July 2014 .

[81] Westpower: Waitaha Hydro Scheme Application for Concessions and Assessment of Environmental Effects – July 2014, at page 2 (section 2.2). See also page 3 of that application. See also Otago Daily Times, 31 May 2012 - http://www.odt.co.nz/news/national/211438/westpower-plans-hydro-scheme-waitaha-river

[82] Otago Daily Times, 31 May 2012 - http://www.odt.co.nz/news/national/211438/westpower-plans-hydro-scheme-waitaha-river

from 117 km^2. The 3D map below shows the Kiwi Flat area, the Whirling Waters tributary and the location of the proposed powerhouse, with the Waitaha River draining to the left of the image[83].

Figure 15: 3D map of the Kiwi Flat area, looking upstream and east
Source: Waitaha application[84]



The elevation at the proposed intake is 238 m, and the catchment rises to around 2,200 m at its head. There are 19 small glaciers in the upper reaches of the Waitaha, and at the end of summer, snow exists only on these glaciers and as snow patches, typically above 1,900 m.

The relevance of the Waitaha's hydrology in relation to wholesale electricity prices and financial viability is outlined later in this report.

4.5.2 Conservation values and adverse effects

The Upper Waitaha Catchment, within which the proposed scheme would be located, is an area of outstanding natural values. This is acknowledged by Westpower and its consultants. Westpower's consultant, Boffa Miskell, concludes that:[85]

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[83] Hydrology of the Waitaha Catchment: A report for Electronet Services Ltd, September 2013, Martin Doyle, September 2013, at page 2

[84] Approximate tunnel representation has been added by the author of this report. 3D map comes from "Hydrology of the Waitaha Catchment: A report for Electronet Services Ltd", September 2013, Martin Doyle, September 2013.

[85] Boffa Miskell report at section 4.2.3 – Appendix 9 of Westpower's Waitaha application

> "...based on the above assessment and within the context and relevant policies of the District and Regional Plan, it is assessed that the Upper Waitaha Catchment contains very high, near pristine levels of naturalness and that the landscape (at both a district and regional scale) be considered *"conspicuous, eminent, especially because of excellence".* This includes the area around the powerhouse site."

Boffa Miskell further summarised the natural values of the Upper Waitaha Catchment as follows:

> "It is considered that they hold high intactness, scientific and distinctiveness values, as recognised in the Westland District Plan to be considered outstanding."[86]

The local adverse effects of the proposed scheme on natural character, landscape, visual amenity and recreational (kayaking) values have been assessed as high.[87]

4.6 Need for sub-transmission upgrade

Westpower notes that the proposed scheme could also require a significant upgrade to Waitaha substation and associated distribution lines[88]:

> "The Hokitika to Harihari 66 kV line was purchased from Transpower in 2001 but has only been running at 33 kV since 1993, when a physical optimisation took place. A new generation scheme at Waitaha in South Westland, tentatively planned for 2018/2019, will involve recommissioning the line at a 66 kV voltage level, and upgrading the existing conductor and the connected substations from 33 kV to 66 kV".

Transpower has signalled an issue that will need to be addressed with further embedded generation on the West Coast:

> "Under light load and high West Coast generation conditions high voltage will occur on the 110 kV transmission system. This issue can be easily managed operationally at present. If there are increased levels of embedded generation, this issue will become more significant and may require more intensive operational control of the generating units' voltage set-points."[89]

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[86] Boffa Miskell,page 72

[87] Boffa Miskell, section 5. See also Greenaway Report, Appendix 19 of Westpower's Waitaha application, at pages 8 and 64

[88] Westpower's Asset Management Plan 2014-2024, section 3.12, page 105

http://www.westpower.co.nz/system/files/resources/AssetManagementPlan2014_0.pdf

[89] Transpower's 2014 Annual Planning Report, section 16.10.1 at page 251

4.7 Electricity sold to an unrelated electricity retailer

Westpower would not sell the electricity produced by the Waitaha to consumers. Rather, it would be sold into the wholesale electricity market and/or to one or more electricity retailers (such as Trustpower, which owns and operates several small hydro schemes on the West Coast).

A variety of arrangements would be possible between Westpower and retailers in relation to the Waitaha output. Under any arrangement, the physical dispatch of Waitaha electricity would be coordinated with Transpower as the 'system operator'.

Assuming Waitaha electricity would be sold into the wholesale electricity market, it would be more efficient for Westpower to contract an existing generator to carry out this market function on its behalf, rather than create it internally. For Westpower do it, it would (among other things) have of provide prices and quantities for all its output every half hour, every day of the year, which Westpower is not resourced to do.

One option would be to sell Waitaha electricity into the wholesale electricity market unhedged – that is to say, Westpower would receive the half-hourly spot price (less a fee for its selling agent).

Another option would be for Westpower to enter into a portfolio of contracts-for-difference with one or more electricity retailers covering proportions of the Waitaha's production for some years forward under which the parties agree to pay each other the difference between the wholesale electricity price (sometimes referred to as the 'floating price' or 'spot price') and an agreed fixed price for a specified volume of electricity. This type of financial instrument (which does not involve any physical delivery of electricity) is widely used in the New Zealand electricity system. For the purpose of assessing the Waitaha scheme's financial viability, it is reasonable to assume that the agreed fixed price is close to the average wholesale price expected over the term of the contract.[90]

A third option would be a combination of the two options above – that is, part of Waitaha's could be covered by a portfolio of contracts-for-differences with the rest unhedged. Until recently, Pioneer Generation Limited, a small Central Otago, community-owned electricity generation business, used this model.[91]

To mitigate some of the wholesale price risk in relation to output from the Amethyst scheme, Westpower had an electricity swap to fix the price for a specified volume of generation.[92] It is also reported that Westpower has an off-take agreement with Trustpower in relation to electricity produced by the Amethyst scheme. Trustpower has around 69% of the electricity retail market in Westpower's region.

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[90] It would not be commercially rational for Westpower to agree to a fixed price below the expected average wholesale price, or for the retailer to agree to a fixed price above the expected average wholesale price. However, in practice, there are normally 'winners' and 'losers' under such contracts.

[91] For many years, Pioneer contracted Trustpower to sell Pioneer generation into the wholesale electricity market. In 2013, Pioneer added wholesale hedge trading capability and systems. It is also now selling direct to some customers.

[92] Westpower's 2014 Annual Report, Note 22 to the Financial Statements

4.8 Exporting Waitaha electricity

Westpower advises that "there would only be short periods at low load when there may be power exported from the region and it is not expected to be significant".[93]

It is interesting to note, however, that, in its 2014 Information Disclosure to the Commerce Commission, Westpower shows exports of embedded generation starting at 30 GWh in 2014 reducing to 23 GWh in 2019. The start of this exporting coincides with the start of generation at the Amethyst scheme. Westpower's forecasts indicate that the addition of the Amethyst scheme is expected to cause the equivalent of around 55% of its output to be exported out of the region.[94] It is not clear what proportion of the Waitaha's output would be exported rather than used to reduce volumes from the grid.

4.9 Summary of key engineering features

The key engineering features of the proposed Waitaha scheme are summarised below.

Table 3: Summary of Waitaha scheme – Key features[95]

Feature	Description
Headworks:	
Intake and weir	Elevation 238 m asl
	Intake water diversion channel
	Low level weir
	No storage of water
Subsurface Structures:	
Sediment Settling basin(s)	Sited underground
	Flushing tunnel outlet approximately 400 m down Morgan Gorge
Tunnel	Approximately 1.5 km long
	Maximum dimensions 8 m wide x 7 m high

[93] Westpower's Answer to Q21 - http://www.westpower.co.nz/news/article/questions-and-answers-waitaha-hydro

[94] Westpower's Information Disclosure of 2014 indicates that until 2014, electricity supplied from distributed generation was steady at around 88-91 GWh pa. From 2015 onwards, Westpower forecasts that distributed generation will produce about 137 GWh of which about 25 GWh will be exported. If the Amethyst generates around 46 GWh pa, this indicates that around 55% of its output will be exported (unless the 25 GWh to be exported comes from Trustpower's local generation). Either way, the addition of the Amethyst is expected to cause the equivalent of around 55% of its output to be exported out of the region.

[95] Westpower: Waitaha Hydro Scheme Application for Concessions and Assessment of Environmental Effects – July 2014 - page viii

Feature	Description
	Varying supports and rock conditions
Penstock	Maximum 2.7 m diameter
	Approximately 1.7 km long
	Bifurcated and buried between tunnel exit portal and powerhouse
	Or alternatively a pressure tunnel
Powerhouse Site:	
Powerhouse	Elevation 130 m asl
	Approximately 15 m x 30 m
	Maximum height above ground 10 m
	5 m underground
	Shape and size determined by generating equipment housed within
Turbines	2 turbines
Switchyard	Area approximately 20 m x 20 m
Main Access Road	Located between the end of Waitaha Road and the powerhouse and lower tunnel portal exit
	Total length approximately 7 km long
	Approximately 2.0 km on conservation land
Transmission Route	66 kV
	Follows road access route within conservation land
Maximum Peak Output	16 – 20 MW
Annual output	115 – 120 GWh
Maximum water take	23 m3/s (cumecs)
Minimum Residual flow	3.5 m3/s (cumecs) immediately below intake
Gross Head	Approximately 100 m

5. Tests of financial viability and electricity need

5.1 Outline of this section

This section 5 is divided into the following parts:

- Summary of key points
- Financial viability and electricity need in statutory framework
- Fiordland mono-rail precedent
- Financial viability and electricity need in relation to new generation
- Methodology
- Underlying logic
- Meaning of full cost ('unit cost')
- Meaning of LRMC
- Meaning of SRMC
- Environmental costs
- Sale of Waitaha electricity
- Importance of wholesale prices for investment in new generation
  - Spot price process
  - Competition and energy-only
  - Prices trend to cost of next cheapest new power station

5.2 Summary of key points

The key points in this section 5 are as follows:

- "Firms should only invest in additional generation plant when the wholesale electricity price and frequency of supply scarcity generates sufficient operating surplus to justify new generation plant."[96] The question in this case is, therefore, whether relevant wholesale electricity prices and frequency of scarcity would generate sufficient operating surplus to justify the Waitaha scheme. If not, it is not financially viable.

- When the data is not available to carry out a detailed discounted cashflow (DCF) analysis, the orthodox methodology for assessing whether a new generation project is likely to be financially viable is to measure whether wholesale prices likely to be received over the medium to longer term for electricity sold from the proposed scheme are, on average, above or below the full cost of producing it – if below, the proposed scheme is negative in net present value terms, which means it is neither an efficient choice of new generation nor financially viable.

[96] Test for investment in new generation set out in "A Critique of Wolak's Evaluation of the NZ Electricity Market: Introduction and Overview" by Prof Lewis Evans, Seamus Hogan and Peter Jackson, Working Paper No. 08/2011 at pages 9-10

- The full cost of electricity from a generation scheme includes not just operating costs, but also capital costs. This is called the 'unit cost'. It is the wholesale electricity price a generator needs to earn, on average, in order to recover capital and operating costs and earn an economic return on investment.

- Some interested parties tend to over-look or under-value the cost of capital. In hydro generation, operating costs are relatively very low, but the cost of capital is relatively high. It is driven by relatively high construction costs. It also needs to include an appropriate risk-adjusted return on equity, as well as debt.

- From a legal point of view, it is clear under Part 3B of the Act that, if the scheme is not needed or not financially viable, it is unlikely to be "appropriate" in terms of section 17S(2) of the Act to incur net adverse effects on conservation values.

More information on financial the test of financial viability and how the New Zealand market prices electricity in the wholesale market is set out in section 5 of this report.

5.3 Financial viability and electricity need in statutory framework

The place of financial viability and electricity need as relevant factors in deciding whether to grant concessions under Part 3B of the Conservation Act 1987 is outlined in some detail in section 2 of this report. From a legal point of view, it is clear under Part 3B of the Act that, if the scheme is not needed or not financially viable, it is unlikely to be "appropriate" in terms of section 17S(2) of the Act to incur net adverse effects on conservation values.

5.4 Fiordland mono-rail precedent

The Minister commissioned[97] independent experts to provide advice on the issue of financial viability in relation to the monorail proposal, on the basis of which he decided that the proposal would not be financially viable. Concerns focused particularly on market demand and the cost of construction[98].

In reviewing the monorail proposal, the reviewer – Ian Dickson & Associates – defined a standalone business to be financial viable[99]:

> "...when it occupies a place in the market that enables it over the long term to:
> - meet its payroll, tax and creditor obligations as they fall due
> - maintain and, when necessary, refurbish or replace its operating assets to maintain its operating capability
> - pay its capital providers returns that meet their expectations."

[97] Presumably under section 17S(4)(a) of the Conservation Act 1987

[98] Letter dated 29 May 2014 from Minister of Conservation to Mr Bob Robertson, at para 44

[99] "Fiordland Link Experience Business Plan Review", Ian Dickson & Associates, 16 March 2014, section 3, page 21- http://www.doc.govt.nz/Documents/about-doc/news/issues/review-fiordland-link-business-plan.pdf.

The definition also noted that a stand-alone business is "independent and receives no financial support from shareholders or other organisations"[100].

The reviewer of the monorail proposal applied discounted cashflow (DCF) analysis to test its financial viability. In a DCF analysis framework, a business is viable when it "generates sufficient free cash flow to meet all future operating and capital expenses, and pay investors a return just equal to their weighted average required return on capital provided", which involves "constructing a representative DCF model of the subject business using known and plausible data for calibration over a sufficiently long period to capture a full investment cycle, estimating the return required by capital providers and the mix of capital types, and identifying the plausible combinations of business value drivers that result in a non-negative NPV."[101]

5.5 Financial viability and electricity need in relation to new generation

"Firms should only invest in additional generation plant when the wholesale electricity price and frequency of supply scarcity generates sufficient operating surplus to justify new generation plant."[102]

The question in this case is, therefore, whether relevant wholesale electricity prices and frequency of scarcity would generate sufficient operating surplus to justify the Waitaha scheme. If not, it is not financially viable.

For a new generation scheme to be embedded in the local distribution network, the assessment needs to take into account the benefit of any reduction in transmission costs (caused by the proposed new generation) for electricity still purchased from the grid.

5.6 Methodology

As noted in section 5 of this report, when it is not possible to carry out a detailed discounted cashflow (DCF) analysis, the orthodox methodology for assessing whether a new generation project is likely to be financially viable is to measure whether wholesale prices likely to be received over the medium to longer term for electricity sold from the proposed scheme are, on average, above or below the full cost of producing it – if below, the proposed scheme is negative in net present value terms, which means it is neither an efficient choice of new generation nor financially viable.

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[100] "Fiordland Link Experience Business Plan Review", Ian Dickson & Associates, 16 March 2014, section 3, page 21 – footnote 8

[101] "Fiordland Link Experience Business Plan Review", Ian Dickson & Associates, 16 March 2014, page 4 and section 3, page 21

[102] Test for investment in new generation set out in "A Critique of Wolak's Evaluation of the NZ Electricity Market: Introduction and Overview" by Prof Lewis Evans, Seamus Hogan and Peter Jackson, Working Paper No. 08/2011 at pages 9-10

5.7 Underlying logic

The underlying logic in deciding whether to invest new electricity generation is as follows:

- Is existing supply capacity sufficient to meet expected demand growth over the medium term? This is the essential test of whether new generation is needed.

- If not, what is the most cost-effective way of meeting the expected shortfall? Options include new generation, transmission and/or demand-side measures (such as energy efficiency and load management).

- For new generation, key variables include:
  - Size – what capacity and output?
  - Type – in particular, what type of fuel: water, steam, gas or coal?
  - Timing – when to build, and
  - Location – what is the best location relative to, among other things, transmission and consumers?
  - Cost – what is the total cost of establishing and operating the scheme?

- What is the full cost of producing a unit of electricity from the proposed power scheme? The meaning of full cost is outlined below.

- What wholesale market prices are likely to be received for electricity produced by the proposed scheme over the medium term?

- Are those expected wholesale market prices above or below its full cost?

- Is the full cost of electricity from the proposed scheme likely to be cheaper than alternative new generation or demand-side options that competitors may offer into the market? [This threat from competitors is normally factored into forecasting the wholesale electricity price path. However, in this context, it is helpful to highlight the importance of assessing competitors' options, and other alternatives, in determining whether a new generation proposal is likely to be economic].

As noted above, if wholesale market prices likely to be received over the medium to longer term for electricity sold from the proposed new generation scheme are, on average, below the full cost of producing it, the scheme is probably not financially viable.

If Waitaha electricity were not sold into the wholesale electricity market, the question is whether the full cost of producing it is likely to be cheaper over the medium term (taking into account any reduction in transmission costs) than the wholesale price of electricity from the transmission grid over the medium term if the Waitaha power was not produced.

With detailed hydrology and wholesale price data, more specific prices can be matched to more specific electricity output, which enables a more detailed comparison of expected revenues against the estimated full cost of producing the electricity. That more granular analysis therefore enables a more definitive conclusion in relation to financial viability.

This report applies the tests outlined above to the Waitaha scheme as a stand-alone business to provide a desk-top analysis of whether it is likely to be financially viable. This report also sets out a reasonably detailed evaluation of whether the proposed scheme is needed from an electricity perspective.

5.8 Meaning of full cost ('unit cost')

The full cost of electricity from a generation scheme includes not just operating costs, but also capital costs. This is called the 'unit cost'.[103] It is the wholesale electricity price a generator needs to earn, on average, in order to recover capital and operating costs and earn an economic return on investment.[104] Put another way:

> "Risk-averse investors require recovery of capital costs with a suitable premium for risk, as well as the fixed and variable operating costs they incur in operations".[105]

Some interested parties tend to over-look or under-value the cost of capital. In hydro generation, operating costs are relatively very low, but the cost of capital is relatively high. It is driven by relatively high construction costs. It also needs to include an appropriate risk-adjusted return on equity, as well as debt.

The components of 'unit cost' are outlined further in section 11 of this report, which examines the likely economics of the Waitaha scheme.

5.9 Meaning of LRMC

Typically (but not strictly), the unit costs of alternative new generation projects are ordered in sequence from least expensive to most expensive. This is called the merit order. The 'long run marginal cost' (or 'LRMC') generally refers to the next cheapest station in the merit order.

In the context of a particular generation project, LRMC is sometimes used more loosely referring to the project's 'unit cost'. [106] As explained in section 9 of this report, this seems to be the sense in which 'LRMC' is used in MBIE's LRMC modelling. MBIE describes 'LRMC' as "a common measure used to compare the relative costs of new generation options over their expected lifetimes."[107]

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[103] Internationally, this is called the ""LCoE", which is the "Levelised Cost of Electricity"

[104] MBIE defines this a project's LRMC – http://www.med.govt.nz/sectors-industries/energy/energy-modelling/modelling/new-zealands-energy-outlook-electricity-insight/interactive-electricity-generation-cost-model

[105] "A Critique of Wolak's Evaluation of the NZ Electricity Market: Introduction and Overview", Prof Lewis Evans, Seamus Hogan and Peter Jackson, Working Paper No. 08/2011 at page 9

[106] As noted above, MBIE defines LRMC as "the wholesale electricity price a generator needs to earn, on average, in order to recover capital and operating costs and earn an economic return on investment" – http://www.med.govt.nz/sectors-industries/energy/energy-modelling/modelling/new-zealands-energy-outlook-electricity-insight/interactive-electricity-generation-cost-model .

[107] MBIE's 2015 Draft EDGS, para 96

5.10 Meaning of SRMC

The 'short run marginal cost' (or 'SRMC') is the cost of producing or consuming one more unit of electricity in a half hour period.[108] (As explained below, the New Zealand wholesale electricity market prices electricity every half hour). The main driver of SRMC is the value of the fuel (which includes water) used in producing electricity in the relevant half hour period. It does not include capital costs or an appropriate return on investment.

For hydro generation, particularly run-of-river schemes (which cannot store water or control the periods when water flows into generation plant), the SRMC tends to be low, particularly compared to generation using thermal fuel (gas, coal or diesel).

5.10 Environmental costs

In New Zealand, environmental costs are factored in when decisions are made as to whether the natural resources in question can be accessed and/or used. If the environmental costs are too high, access or use may be denied or restricted.[109]

5.11 Sale of Waitaha electricity

As outlined in section 4 of this report, a variety of arrangements would be possible for the sale of electricity from the Waitaha scheme. For the purpose of assessing the scheme's financial viability, the revenue outcomes for Westpower should be equivalent under any option.

Further, Waitaha electricity would be sold by a retailer to its customers at the retailer's price. There is no reason to expect a retailer to sell Waitaha power at special (discounted) price for its local consumers relative to electricity it purchases from the transmission grid.

5.12 Importance of wholesale prices for investment in new generation

In the New Zealand electricity market, the financial viability of a new generation project is perhaps most strongly influenced by wholesale electricity prices. It is therefore important to understand the basic dynamics of wholesale electricity prices.

5.12.1 Spot price process

The process of establishing the wholesale electricity price is usefully set out in a decision of the New Zealand High Court in 2012. The following is a mix of extracts from that decision with additional commentary: [110]

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[108] 2009 Ministerial Review, Volume 2, page 11, Definition of SRMC

[109] Ideally, environmental externalities should be priced into the cost of the development.

[110] Description of spot price process draws on a High Court decision reported in [2012] NZHC 238, paras 17 to 22. Also a research note by Woodward Partners - http://media.nzherald.co.nz/webcontent/document/pdf/201340/woodward_Meridian.pdf

- Wholesale market prices are established every half hour at 248 nodes (grid exit points) across New Zealand by a process of offers from generators (to supply a certain quantity of electricity) and bids from retailers (to buy a certain quantity of electricity). Each day is divided into 48 trading periods of a half hour each.

- In each trading period a generator may offer to supply an identified quantity of electricity at an identified price or prices at a particular node or nodes.

- There is no maximum offer price.

- The System Operator‛s function is, for any half hour period, to accept offers to supply electricity starting at the lowest offer and moving up the price bands of the offers until demand is met.

- This "demand" level of electricity is then dispatched to meet the demand.

- The highest generator‛s offer accepted in any trading period by the System Operator to meet demand then becomes the price paid for all the electricity offered and supplied in that trading period.

- Offer prices may vary between nodes. The System Operator seeks to send the lowest price electricity offered between nodes to satisfy demand at the lowest possible price.

In the short term, the wholesale market price is driven mainly by short term variations in generation capacity, transmission outages and constraints, changes in demand (often due to climatic temperatures), and changes in hydrological conditions (water inflows and water storage in the hydro catchments).

During periods of low demand (such as weekends), only low-cost plants are needed to satisfy the low demand so the spot price is also low. When demand is high (such as during cold winter days), more expensive thermal plants are also needed to satisfy the greater demand, and the spot market price is higher.

5.12.2 Competition and energy-only

As the Chairman of the Electricity Authority has highlighted[111]:

> "In the wholesale electricity market, prices are determined by competition between generators offering to supply and these offers being matched to demand. The values of the different generation assets are driven by market prices and not vice versa"

New Zealand's wholesale electricity market operates on energy-only marginal prices – that is to say, the wholesale electricity price generally reflects the cost of producing one more unit of electricity from the next least expensive source. There is no separate payment for the cost of generating capacity; the cost of capacity must be covered by the energy price.

[111] "The Economics of Electricity", Dr Brent Layton, 4 June 2013, at para 44

5.12.3 Prices trend to cost of next cheapest new power station

As supply becomes tighter relative to demand over the medium term, wholesale prices trend toward the full cost of producing electricity from the next cheapest new power station.

As the Electricity Authority notes:

> "The structure of electricity generation and prices for new plant dictate the structure and underlying trends of electricity prices. In the short term, prices tend towards the cost of running the most expensive plant needed to meet demand. Prices tend to rise and fall in cycles as more expensive plant is needed to serve demand. This provides incentives to invest in new electricity generation, and the kind of investment that takes place will tend to reflect movements in the costs of different technologies..." [112]

The 2009 Ministerial Review of Electricity Market Performance similarly observed that:

> "...in any market faced with the need to build new capacity (as a consequence of increased demand and the need to replace obsolete capacity) average prices would be expected to track the cost of building new capacity. This is both because such prices provide the incentive needed to build new capacity and because, in a competitive market, all prices trend to the same level"[113]

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[112] Electricity Authority: "Electricity market performance: 2010–2011 in review", at page 6 – https://www.ea.govt.nz/monitoring/year-in-review/2011-review-of-electricity-market-performance/

[113] "Ministerial Review of Electricity Market Performance", Electricity Technical Advisory Group and the Ministry of Economic Development, August 2009, Volume 2, at 239

6. Supply and demand in Westpower's region – 2001 to 2014

6.1 Outline of this section

This section of the report sets out a reasonably detailed overview of electricity supply and demand in Westpower's region between 2001 and 2014. Its purpose is to convey the context in which the Waitaha scheme was proposed and, in particular, the strong growth expectations that drove the proposal, and how the electricity supply and demand outlook has declined significantly over the last four years.

This section 6 is divided into the following parts:

- Summary of key points
- Demand forecasts: 2001 to 2010
- New supply proposals: 2001 to 2010
    - Range of new supply options
    - Fever-pitch expectations: "West Coast held back"
    - Not all new supply options needed
- Demand forecasts: 2010 to 2014
- Actual demand compared to forecast demand: 2003 to 2014
- Decisions on new supply options for the West Coast
    - Transmission upgrade: 2007 to 2011
    - Amethyst hydro scheme: 2004 to 2013
    - Waitaha hydro scheme: 2002 to 2014
    - Diagram of key milestones in Amethyst and Waitaha development
    - Other West Coast generation options: 2003 to 2014

6.2 Summary of key points

The key points in this section 6 are as follows:

- The Amethyst and Waitaha schemes were developed along a similar time-frame. They emerged in a period of relative economic boom on the West Coast – 2001 to 2010. Forecasts of electricity demand growth in that period became almost frenzied. Several new generation schemes were proposed during those 10 years offering significantly more additional capacity than was required.

- The perception was that "the Coast has been leading the country in economic development, thanks to its dairy, mining and tourism industries, but it's always been held back to some extent by having to import...power from elsewhere". This view that the Coast is held back by not being self-sufficient in electricity is still a key plank of

Westpower's rationale for the Waitaha scheme in its application to the Minister of July 2014.

- All of Westpower's growth forecasts since 2003 at least have been consistently over-optimistic, some rather wildly so. In short, the rate of growth has been massively over-estimated and the rate of decline has been significantly under-estimated.

- When the decline in electricity demand started toward the end of 2010, Transpower and Westpower had started work on projects to significantly increase electricity supply capacity for Westpower's network. Based on an approval obtained in 2008, Transpower completed a significant upgrade of transmission services into the West Coast, effectively doubling supply capacity.

- In 2009/10, Westpower started construction work on its Amethyst hydro scheme, which was commissioned in mid 2013. Westpower's Information Disclosure would suggest that a significant proportion of the Amethyst's output is expected to be exported outside the region.

- Consistent with rational economic decision-making, most of the other West Coast new generation projects under development between 2003 and 2012 have been cancelled or deferred indefinitely.

6.3 Demand forecasts: 2001 to 2010

Pre-feasibility work on the Waitaha hydro scheme was progressed in 2005.[114] Westpower announced its intention to proceed in 2007.[115] In this period, expectations of growth in electricity demand were very high:

- In 2003, Westpower forecast peak demand to grow by 72.4% from 35.6 MW to 61.5 MW;[116]

- In 2007, Transpower and Covec (economic consultants) forecast peak demand to increase over 10 years by between 69 and 210 percent;[117]

- Also in 2007, Brown, Copeland & Co advised Westpower that a growth rate of 3% to 4% per year in base load electricity demand over the 5 to 10 years was realistic;[118]

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[114] Minutes of meeting of West Coast Conservation Board, 21 September 2012 http://www.doc.govt.nz/Documents/getting-involved/nz-conservation-authority-and-boards/conservation-boards-by-region/west-coast-tai-poutini/minutes/wctpcb-minutes-sept-12.pdf

[115] See also http://www.stuff.co.nz/archived-stuff-sections/archived-business-sections/business/46988/Hydro-scheme-latest-in-West-Coast-energy-surge

[116] Westpower's Asset Management Plan 2004 to 2014

[117] Transpower – West Coast Grid Upgrade Project – Proposal – Appendix C, October 2007, revised application in March 2008 - http://www.ea.govt.nz/about-us/what-we-do/our-history/archive/operations-archive/grid-investment-archive/gup/2007-gup/west-coast-upgrade-plan/

[118] Transpower – West Coast Grid Upgrade Project – Proposal – Appendix C, October 2007, revised application in March 2008 – see web link above

- In 2008, Sinclair Knight Merz (SKM) projected that peak electricity demand would increase over 10 years from about 26 MW to 85-95 MW – an increase of some 346%; and

- Westpower's forecasts of demand growth reach their high-point 2010 when it planned for peak demand to grow by a spectacular 97.6% over 10 years [from 52.5 MW in 2008/09 to 103.9 MW in 2018/19].[119]

As at 2007-08, the main sources of expected growth in demand for electricity are set out in the table below.[120]

Table 4: Sources of expected electricity demand growth on Westpower's network as at 2007-08. Sources: Transpower and Covec

Source of increased demand	Grid exit point	How likely	Demand increase (MW)	2007 (MW)	2008 (MW)	2009 (MW)	2010 (MW)	2011+ (MW)
Pike River Mine		Definite	14		7	7		
Kaiata Industrial Park	DOB	Definite	4	0.5	1.5	2		
Oceana Gold (Reefton)	RFN	Definite	3.9	3.9				
Oceana Gold (Waiuta)	RFN	Low	1.5			1.5		
Westland Milk (power plant)	HKK	Likely	5					7.8
Westland Milk (protein)	HKK	Complete	4.2					
Dairy farms	DOB	Likely	0.9	0.1	0.3	0.3	0.2	
Dairy farms	HKK	Possible	0.55		0.35	0.1	0.1	
Solid Energy (Spring Creek)	DOB	Confirmed	1	1				

[119] Westpower's Asset Management Plan 2010 to 2020

[120] Transpower: "West Coast Grid Upgrade Project – Attachment – Technical Report", October 2007 at section 2.4; and Attachment C (Covec Report) to Transpower's West Coast GUP application of October 2007

Source of increased demand	Grid exit point	How likely	Demand increase (MW)	2007 (MW)	2008 (MW)	2009 (MW)	2010 (MW)	2011+ (MW)
Solid Energy (Rocky Creek)	DOB	Confirmed	0.2	0.2				
Roa Coal Mine	DOB	Complete	0.8					
Franz Joseph Holiday Park	HKK	Complete	0.8					
Railway - electrification	OTI	Low	11					11
Gibbs Road – Franz Joseph	HKK	Possible-likely	2.27	0.1	0.6	0.95	0.6	
Other projects			4.57	1.5	0.9	1.1		
Total			**50.7**	**7.3**	**10.6**	**13**	**0.9**	**18.8**

6.4 New supply proposals: 2001 to 2010

6.4.1 Range of new supply options

Several new generation schemes were proposed during this period in response to these demand forecasts of economic boom. Some of the schemes are outlined in Table 5 below.

Table 5: New generation proposals – 2001 to 2010.
Sources: Trustpower, Meridian, HDL, Transpower, Westpower

Scheme	Size	Owner	RMA consents	DOC concessions
Arnold River	46 MW	Trustpower	Yes (Nov 2008; E/Court, Dec 2010)	[Not required]
Mohikinui River	65-85 MW	Meridian	Yes in April 2010, but appeals lodged with E/Court	No
Stockton Mine	35 MW	Solid Energy	Yes in May 2012 on appeal to E/Court	

Scheme	Size	Owner	RMA consents	DOC concessions
Stockton Mine	25 MW	Hydro Developments Limited (HDL)	Yes (Jan 2010) and agreement with Solid Energy (Oct 2010)	
Transmission line upgrade	New 110kV line and other works (Reefton to Dobson)	Transpower	Yes	Not required
Amethyst River	7 MW	Westpower	Yes	Yes
Waitaha River	16–20 MW	Westpower	Yet to apply	Applied to DOC in July 2014

6.4.2 Fever-pitch expectations: "West Coast held back"

The growth outlook became almost feverish with The Press reporting in 2009 that:

> "The West Coast Regional Council is investigating how the region could harness its hydro potential and become a powerhouse. There are six hydro schemes consented or proposed for the Coast, with the potential to produce 200 megawatts and make the region a net exporter of electricity. Regional council chief executive Chris Ingle this week presented a report to the council recommending it look into how it could encourage hydro projects. The report said electricity demand on the Coast was expected to double in the next 10 years to 110MW. It could be more than 200MW by 2040" [121]
>
> ...

The perception was that:

> "the Coast has been leading the country in economic development, thanks to its dairy, mining and tourism industries, but it's always been **held back** to some extent by having to import...power from elsewhere".[122] [emphasis added]

This view that the Coast is held back by not being self-sufficient in electricity is still a key plank of Westpower's rationale for the Waitaha scheme in its application to the Minister of July 2014.

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[121] The Press, 17 July 2009 - http://www.stuff.co.nz/the-press/news/2601161/Council-thinks-big-on-hydro-power-projects

[122] Article in "Energy NZ" Vol.4, No. 4, July-Aug 2010 – "West Coast hydro renaissance" - http://www.contrafedpublishing.co.nz/Energy+NZ/Vol.4+No.4+July-August+2010/West+Coast+hydro+renaissance.html. See also the article in New Zealand Energy and Environment Business Alert – December 22nd, 2007http://nzenergy-environment.co.nz/home/free-articles/west-coast-electricity-demand-set-to-skyrocket-as-economy-booms.html#sthash.y2C5cfoF.dpuf

6.4.3 Not all new supply options needed

The total capacity of all the new supply options for the West Coast referred to in the Table above was clearly considerably larger than even the most aggressive forecast of increased electricity demand. Therefore, even when they were planned or proposed, only a limited number of those new supply options were likely to have been needed or economic, even under the most optimistic growth scenario.

The transmission upgrade alone would meet demand growth for more than 15 years. In its 2007-08 report to the Electricity Authority, Transpower advised that the upgrade:

> "should provide sufficient transmission capacity into the West Coast out till around 2025"[123]; and

In its 2008 report, Sinclair Knight Merz advised that construction of Trustpower's 46 MW hydro scheme on the Arnold River and Meridian Energy's 65 – 85 MW hydro scheme on the Mohikinui River would more than meet this projected growth in demand and likely make the region an exporter of electricity".[124]

As it turned out, the two capacity increases put in place for Westpower's region were the transmission line upgrade and Westpower's Amethyst hydro scheme. This is outlined further below.

6.5 Demand forecasts: 2010 to 2014

Westpower's strong growth forecasts continued during this period but at a lower rate of growth:

- By 2009, actual peak demand in Westpower's region reached about 53.2 MW, an increase of 63.5% on 2001.
- In 2010, Westpower forecast the dramatic growth to continue with peak demand climbing 97.6% over 10 years from 52.5 MW in 2008/09 to 103.9 MW in 2018/19.[125]
- In 2011, with the explosion at Pike River Mine in late 2010, Westpower adjusted its expectations significantly downwards relative to its forecast the previous year. However, its 2011 forecast[126] still assumed growth of 40% over 10 years, which was still very substantial, just not as dramatic as the 97.6% growth it forecast in 2010.

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[123] "Proposal for the West Coast Grid Upgrade Investment Proposal", Transpower, October 2007, section 2.2, page 6.

[124] "Renewable Energy Assessment – West Coast Region", Sinclair Knight Merz (SKM), 4 August 2008, section 2.7, page 22

[125] Westpower's Asset Management Plan 2010 to 2020

[126] Westpower's Asset Management Plan 2011-2021 at page 132, Table 5.4.1http://www.westpower.co.nz/system/files/resources/amp_2011_2020.pdf

- In 2011, Transpower was also forecasting significant step-change growth in demand for electricity on the Westpower's region, with most of this growth expected from:[127]

Table 6: Transpower's 2011 forecast of expected electricity demand growth on Westpower's network

Source of increased demand	Amount of extra peak power required	Probability of demand increase	Earliest date required
Pike River Mine	10 MW	50%	2013
Westland Dairy	5 MW	70%	2014
Mining	4 MW	70%	2015
Mining	4 MW	70%	2018

- In 2012, Westpower made a further downward adjustment in its forecast. However, it continued to project significant growth of about 19% over 10 years [from 55 MW in 2010 to 65.4 MW in 2020].

- Westpower's 2013 forecast made further downward demand adjustments across the forecast period relative to the 2012 forecast. However, it still assumed demand growth of 23.4% over 10 years [from 50 MW to 61.6 MW].

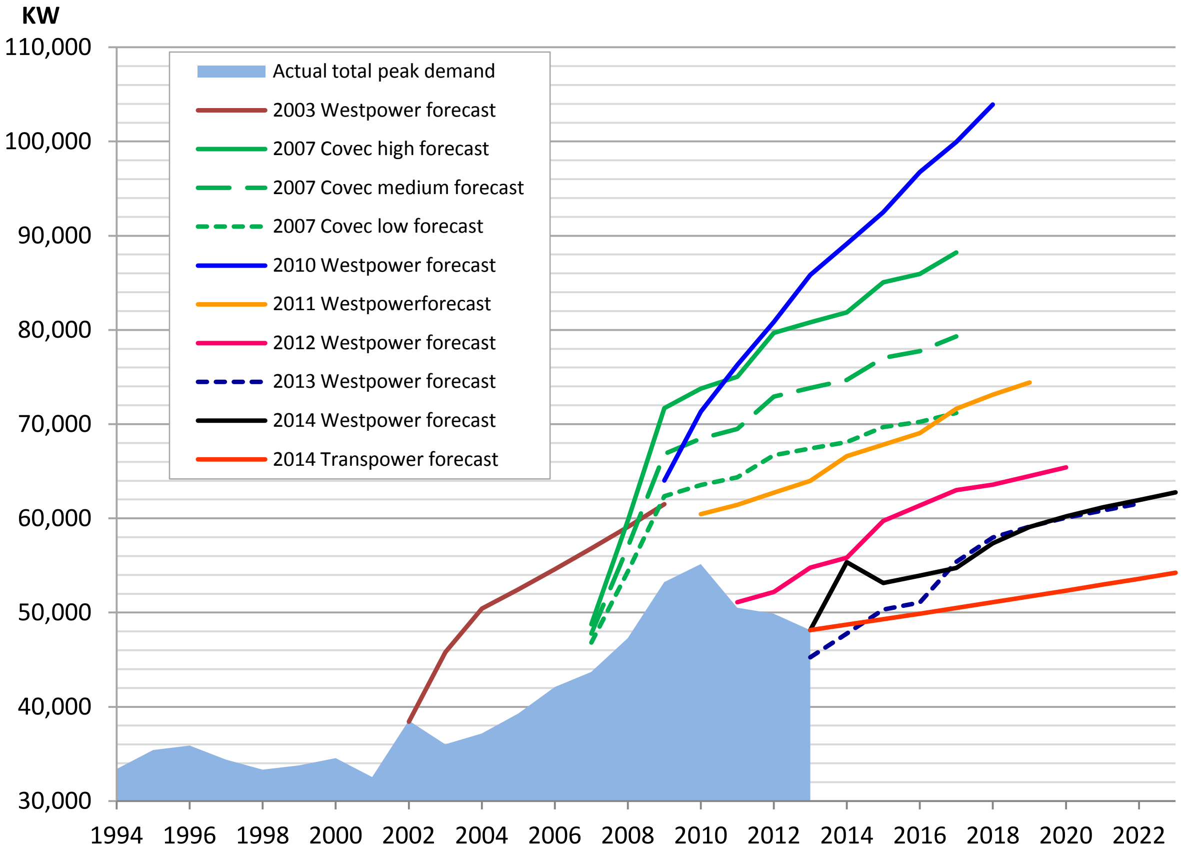
To sum up, Westpower's growth expectations reached an extreme high in 2010. Since then, their forecasts have been adjusted incrementally downwards but continue to assume reasonably strong growth. The outlook from 2014 is discussed further below.

6.6 Actual demand compared to forecast demand: 2003 to 2014

Actual electricity demand in Westpower's region compared to the various forecasts referred to above is shown in the chart below. (A larger version of this chart is set out in appendix 1 of this report).

[127] Transpower: "Long-term demand forecast", September 2011, Appendix A, Figure 25, Page 43; and table on page 22 https://www.transpower.co.nz/sites/default/files/plain-page/attachments/transpower-demand-forecast-sept-2011.pdf.

Figure 16: Demand forecasts since 2003 relative to actual demand on Westpower's network.
Sources of data: Westpower, Transpower, Covec



As can be seen in the chart above, except for Transpower's 2014 forecast, all of the growth forecasts since 2003 at least have been consistently over-optimistic, some rather wildly so. In short, the rate of growth has been massively over-estimated and the rate of decline has been significantly under-estimated.

After a period of net decline between 1994 and 2001, peak electricity demand in Westpower's region increased steeply from 2001 to 2010 by 69%. Growth came mainly from a small number of large customers: Westland Dairy, Pike River mine, Solid Energy, Oceana Gold, a couple of other small mining operations, and associated industrial and commercial activity[128].

However, the 10 year streak of rapid growth came to rather abrupt end in 2010. Key causes of the decline over the last four years included:

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128 Among other things, this highlights Westpower's exposure to a very small number of large customers. Indeed, between 2008 and 2011, Westpower's largest five customers made up around 45% of total electricity consumption and their consumption increased by over 40% between 2008 and 2011. However, in the same period, the number of Westpower's large customer connections declined by 15% [see Commerce Commission's Review of Westpower's performance, 2008-2011 http://www.comcom.govt.nz/regulated-industries/electricity/electricity-distributors-performance-from-2008-to-2011/edb-performance-westpower/]. This highlights Westpower's significant exposure to changes in electricity consumption by its small number of large customers [see Westpower's Asset Management Plans since at least 2003. For example, 2014 version at section 5.2, page 125

http://www.westpower.co.nz/system/files/resources/AssetManagementPlan2014_0.pdf].

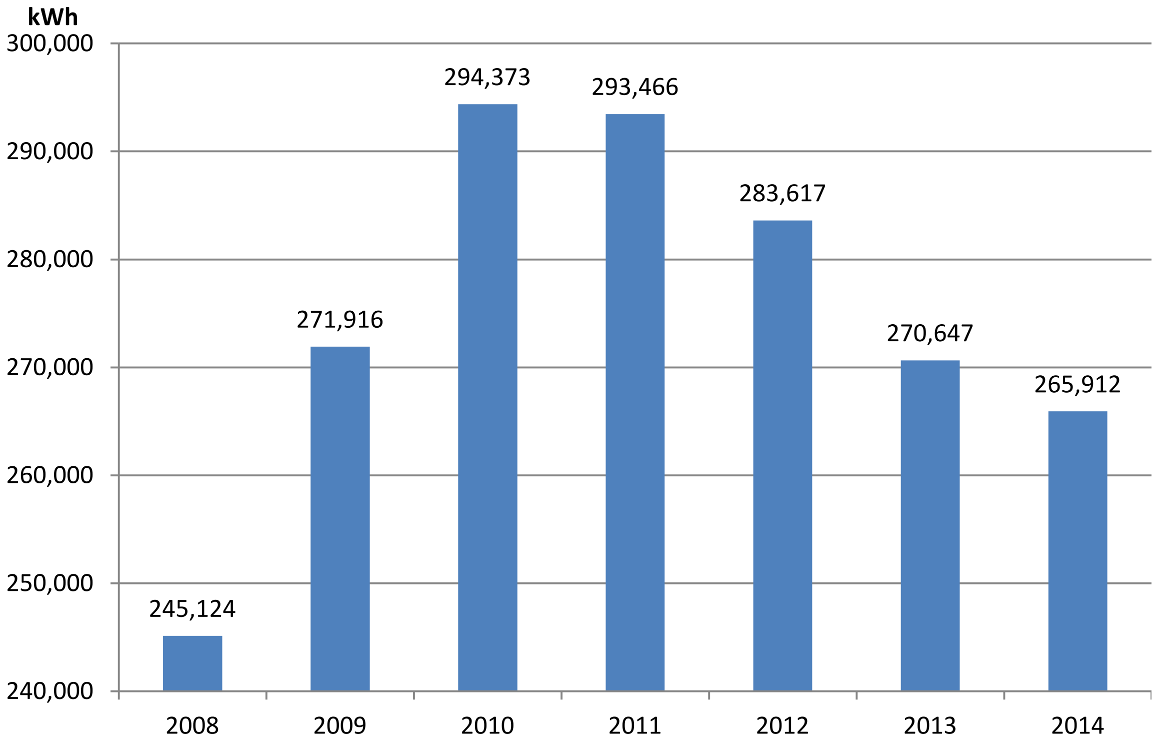
— The Pike River mine disaster in November 2010;

— Solid Energy's 2012 decision to suspend all the work at its Spring Creek mine[129]; and

— Oceana Gold's announcement in June 2013 that its open pit at Reefton, which was commissioned in 2007, is to be mothballed by mid-2015 due to declining gold prices[130].

In the neighbouring network of Buller Electricity, Holcim announced in June 2014 that it would be closing its cement factory at Westport in the second half of 2016[131].

Figure 17: Total energy delivered on Westpower's network.
Source: Westpower's Information Disclosure to Commerce Commission



[129] Westpower's planning assumption is that Pike River and Spring Creek will not restart within the next four to five years – see Westpower's Asset Management Plan 2014-2024 – Figure 5-1

http://www.westpower.co.nz/system/files/resources/AssetManagementPlan2014_0.pdf. Note that this planning assumption seems somewhat optimistic

[130] http://www.oceanagold.com/our-business/new-zealand/reefton-open-pit/ and

http://www.odt.co.nz/news/business/262864/oceana-mothball-reefton-gold-mine and

http://www.greystar.co.nz/content/reefton-braced-mine-end

[131] http://www.stuff.co.nz/business/industries/10205132/Another-blow-for-Westport

The prospects of demand growth on Westpower's network in the medium term are weak. This is discussed further in section 10 of this report

6.7 Decisions on new supply options for the West Coast

6.7.1 Transmission upgrade: 2007 to 2011

Based on the 2007 demand forecast by Covec set out in Table 4 above, and on an assumption that peak demand would increase by around 30MW by 2008, Transpower gained approval from the Electricity Authority in 2008 for a significant upgrade in transmission services into the West Coast at a reported cost of around $27m.[132]

The transmission upgrade included a second 110kV line between Reefton and Dobson, a second 110kV line between Reefton and Inangahua, a second 110/66 kV transformer at the Dobson substation, and a new 14 Mvar fast switching capacitor bank at the Hokitika substation[133]. The Hokitika capacitor section of the project was commissioned in June 2010, and the 110 kV line and associated transformer was completed in September 2011.[134]

The 14 MVar switched capacitor bank installed on the 11 KV bus Hokitika substation provides reactive support in order to maintain and stabilise the voltage of Transpower's 66 kV transmission system on the West Coast. The project was fully funded by Transpower, which took over the ownership of these capacitors in June 2010.[135]

The upgrade delivered the following increase in transmission capacity:

	Before upgrade	After upgrade
Into West Coast	30MW	60MW
Out of West Coast	50MW	100MW

Source: Transpower

These numbers are not the thermal capacity of the transmission lines but rather the transfer limits, which are governed by voltage factors. More transmission capacity can be accessed by installing more capacitor banks.

[132] "West Coast Grid Upgrade Project – Proposal – Application for Approval", Transpower, October 2007 at section 2.4.2

[133] Westpower's Asset Management Plan 2014-2024, section 5.4.2, page 136; and Reuters/stuff.co.nz – 7 July 2008 http://www.stuff.co.nz/business/525849/Transpower-gets-first-thumbs-up-for-West-Coast-work

[134] Transpower's Annual Planning Report, March 2014

[135] Westpower's 2014 Asset Management Plan, section 5.7.3 at page 148

Transpower considered that the upgrade:

> "should provide sufficient transmission capacity into the West Coast out till around 2025 [assuming the extremely high growth rates forecast in 2007/08]."[136]

Following the decline in electricity demand between 2010 and 2014, Westpower acknowledges in its 2014 Asset Management Plan that the transmission upgrade has delivered security of supply sufficient to satisfy future economic development:

> "Currently, there is sufficient n-1 transmission capacity available in the transmission network feeding the West Coast, to ensure that major new loads can be supplied on an uninterruptible basis, and so **electricity supply should not be a constraint** to future economic development." [Emphasis added]
>
> "The DOB-TEE A line effectively doubles the transmission capacity, **thus providing security to the West Coast.**"[137] [Emphasis added]

The 2011 upgrade also resulted in a significant improvement in reliability and security of supply. This is outlined further in a section 12.8 of this report.

6.7.2 Amethyst hydro scheme: 2004 to 2013

The environmental impact assessment of Amethyst scheme was prepared in 2003. Westpower says it was approached to become involved in the Amethyst scheme in May 2004.[138] Electricity demand was growing strongly then. Westpower commenced final feasibility and design work in 2006. The Commerce Commission granted the required exemption in November 2006. The Minister granted concessions for the scheme in August 2008. Construction work on the tunnel started in 2010 (around the time that electricity demand reached its peak). The scheme was commissioned in June 2013.

In short, the Amethyst scheme was developed and commenced during the 10 year period of relatively high growth in electricity consumption on Westpower's network. Since then, the market has declined significantly and, as outlined in section 10 the foreseeable outlook is weak.

The Amethyst scheme has a capacity of around 7 MW and can produce about 45 GWh per year[139]. It is a run-of-the-river station that is expected to operate continuously at levels above 3 MW (except for maintenance and fault shutdowns).[140]

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[136] "West Coast Grid Upgrade – Proposal – Application for Approval", Transpower, October 2007, section 2.2, page 6.

[137] Westpower's Asset Management Plan 2014-2024, section 5.4.2, pages 136 and 137

[138] Westpower application to the Commerce Commission, 3 August 2006, at paras 22 and 23 - www.comcom.govt.nz/dmsdocument/10731

[139] http://www.westpower.co.nz/power-generation-amethyst-hydro

[140] Westpower's Asset Management Plan 2013 - 2023, page 141

Westpower's Information Disclosure would suggest that a significant proportion of the Amethyst's output is expected to be exported outside the region.[141]
Among various forms of financial support, Westpower has provided a guarantee to Westpac in relation to the debts owed by Amethyst Hydro Limited.[142] It is reported to have cost $35.6m.[143]

6.7.3 Waitaha hydro scheme: 2002 to 2014

Pre-feasibility work on the Waitaha scheme was progressed in 2005. In December 2007, Westpower announced its intention to proceed with the scheme. For Westpower, the purpose of the Waitaha scheme was "to help meet some of the Coast's anticipated new demand".[144]

In May 2012, Westpower announced that it was continuing to develop the Waitaha scheme, advising that "it would be another small scale run of the river scheme, similar in construction to the Amethyst one".[145] In July 2014, Westpower applied to the Minister of Conservation for concessions under Part 3B of the Conservation Act 1987.

6.7.4 Diagram of key milestones in Amethyst and Waitaha development

The chart below shows key milestones in Westpower's development of the Amethyst and Waitaha schemes. Both were initiated in the early stages of strong economic growth. Both were supported by forecasts of spectacular demand growth. The medium term outlook is now, however, is decidedly weaker. This is discussed further in section 10 of this report.

[141] Westpower's Information Disclosure of 2014 indicates that until 2014, electricity supplied from distributed generation was steady at around 88-91 GWh pa. From 2015 onwards, Westpower forecasts that distributed generation will produce about 137 GWh of which about 25 GWh will be exported. If the Amethyst generates around 46 GWh pa, this indicates that around 55% of its output will be exported (unless the 25 GWh to be exported comes from Trustpower's local generation). Either way, the addition of the Amethyst is expected to cause the equivalent of around 55% of its output to be exported out of the region.

[142] Westpower's 2014 Annual Report – Note 25 to Financial Statements

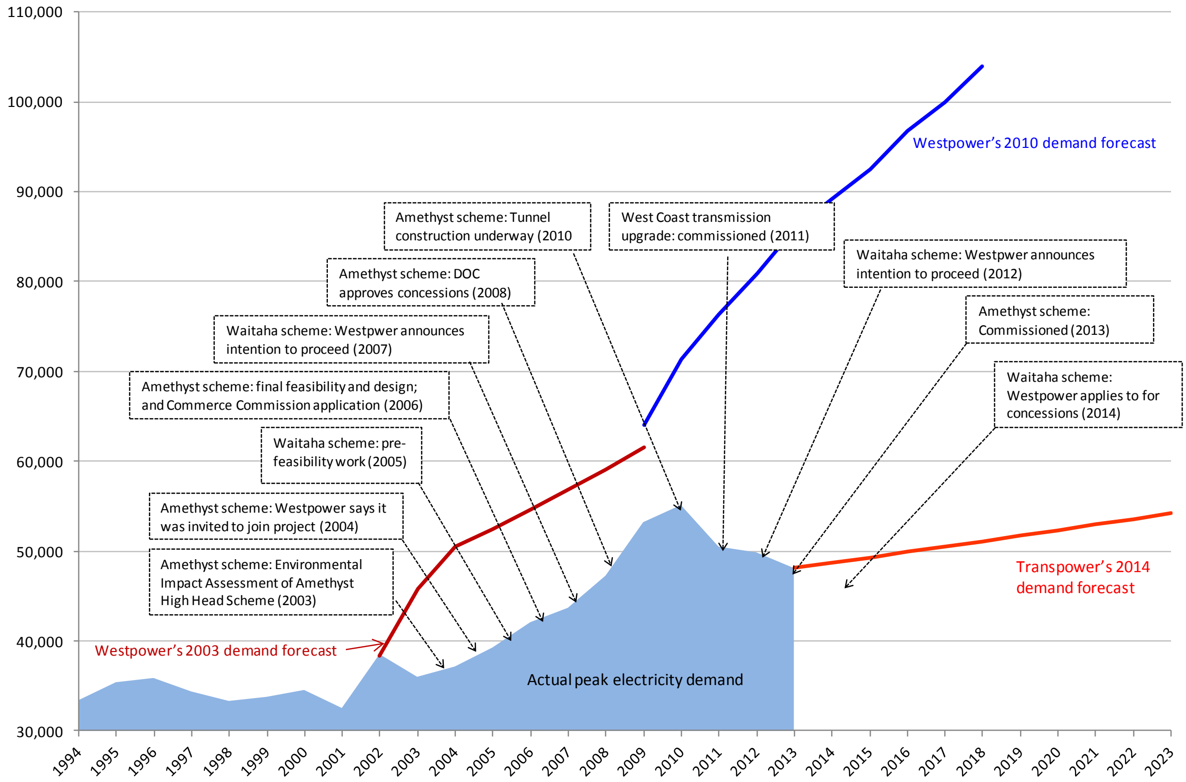
[143] http://www.nzeeawards.org.nz/news/14-11-Celebrating-NZ%27s-talent.cfm

[144] "Westpower, last week announced plans to build a 20MW hydro scheme on the Waitaha River, south of Ross, which it hopes will help meet some of the Coast's anticipated new demand" - New Zealand Energy and Environment Business Alert – December 22nd, 2007

http://nzenergy-environment.co.nz/home/free-articles/west-coast-electricity-demand-set-to-skyrocket-as-economy-booms.html. See also an article by NZPA at http://www.stuff.co.nz/archived-stuff-sections/archived-business-sections/business/46988/Hydro-scheme-latest-in-West-Coast-energy-surge

[145] Otago Daily Times, 31 May 2012 - http://www.odt.co.nz/news/national/211438/westpower-plans-hydro-scheme-waitaha-river

Figure 18: Key milestones in Amethyst and Waitaha scheme development:



6.7.4 Other West Coast generation options: 2003 to 2014

With the decline in electricity demand on the West Coast since 2010 combined with the transmission upgrade in 2011, supply capacity for Westpower's region became significantly greater than demand. As outlined later in the next section of this report, the rest of New Zealand also came into a surplus of supply relative to demand, and wholesale electricity prices became flat.

As a result, and consistent with rational economic decision-making, most of the other West Coast new generation projects under development between 2003 and 2012 have been cancelled or deferred indefinitely, including:

— **Meridian's 65–85 MW hydro scheme on the Mohikinui River:**
Resource management consents were granted in April 2010, but opponents lodged appeals in the Environment Court. Meridian announced in May 2012 that it would not proceed with the project citing "high costs and risks surrounding a project that encroached on environmentally sensitive land"[146]. The full cost of producing electricity from this project is also likely to have been greater than the expected wholesale price from selling it.

[146] http://www.stuff.co.nz/business/industries/6964548/Meridian-pulls-plug-on-Mokihinui-project

— **Trustpower's 46 MW hydro scheme on the Arnold River:**
Resource management consents were granted in November 2008 and upheld by the Environment Court in December 2010. However, Trustpower announced in May 2012 that the project had been "shelved indefinitely...because the economics are not sufficiently attractive...it's just not financially viable"[147].

— **Solid Energy's 35 MW hydro scheme on the Stockton mine:**
Resource management consents were obtained on appeal from the Environment Court in May 2012[148]. However, Solid Energy is likely to have deferred the project indefinitely.

— **Hydro Developments' 25 MW hydro scheme also on the Stockton mine:**
Resource management consents were obtained in January 2010, and an agreement with Solid Energy relating to the access and use of water was achieved in October 2010.[149] However, the project is on hold. The initial developer, Hydro Developments Limited, has re-formed as Hydro Developments (2013) Limited, with two of the initial shareholders continuing[150].

These generation options are discussed further as alternatives in section 13 of this report.

That these projects are not proceeding is not surprising. While the Stockton options are tied up with Solid Energy's future, the change in supply and demand conditions since around 2010 has been key issue in the future of all new generation options. These decisions not to proceed are consistent with the approach of other key electricity companies around New Zealand.

[147] http://www.odt.co.nz/regions/west-coast/209347/west-coast-hydro-scheme-shelved

[148] http://www.scoop.co.nz/stories/BU1205/S00087/stockton-hydro-electricity-scheme-gains-consents.htm

[149] https://nzresources.com/showarticle.aspx?id=1413&guid=30001413 and
http://www.radionz.co.nz/news/regional/58359/stockton-hydropower-deal-agreed and
http://www.nznewsuk.co.uk/business/?id=5699

[150] John Easther – see New Zealand Companies Office Register

7. Supply and demand in New Zealand – 2001 to 2014

7.1 Outline of this section

This section of the report provides an overview of electricity supply and demand in New Zealand between 2001 and 2014. Its purpose is to give a context in which to view changes in supply and demand on Westpower's network, and in particular decisions relating to investment in new supply capacity for Westpower's network. Decisions on whether new generation capacity on the West Coast is required or economic are influenced by the electricity supply and demand situation in New Zealand as a whole, and the capacity to deliver electricity to the West Coast on the national transmission grid.

This section 7 is divided into the following parts:

- Summary of key points
- Change in demand: 2001 to 2014
- Change in supply capacity: 2001 to 2014
- Net surplus of capacity relative to demand
- Wholesale electricity prices: 2010 to 2014
- Impact on new generation projects across New Zealand
- Impact on small hydro proposals – Network Tasman
- Details of new generation built: 2003 to 2014

7.2 Summary of key points

The key points in this section 7 are as follows:

- In the wider context, electricity demand in New Zealand also grew strongly between 1990 and 2010. However, it too has decline significantly since 2010. On the supply side in New Zealand, a large amount of new generation capacity (about 2,207 MW) was built between 2001 and 2014 – equal to about 27%% of total capacity in 2001. The national transmission grid was also substantial upgraded, including increasing the HVDC capacity to 1,200MW, which means, among other things, that electricity can flow relatively freely between the North and South Islands in both directions, transporting electricity from its generation source to where it may be needed.

- The result is a significant surplus of supply relative to demand. Reflecting this capacity surplus and weak demand growth, the trend in wholesale electricity prices over the last few years has been flat, even declining somewhat in real terms. The average of wholesale prices since January 2012 has been about $75/MWh.

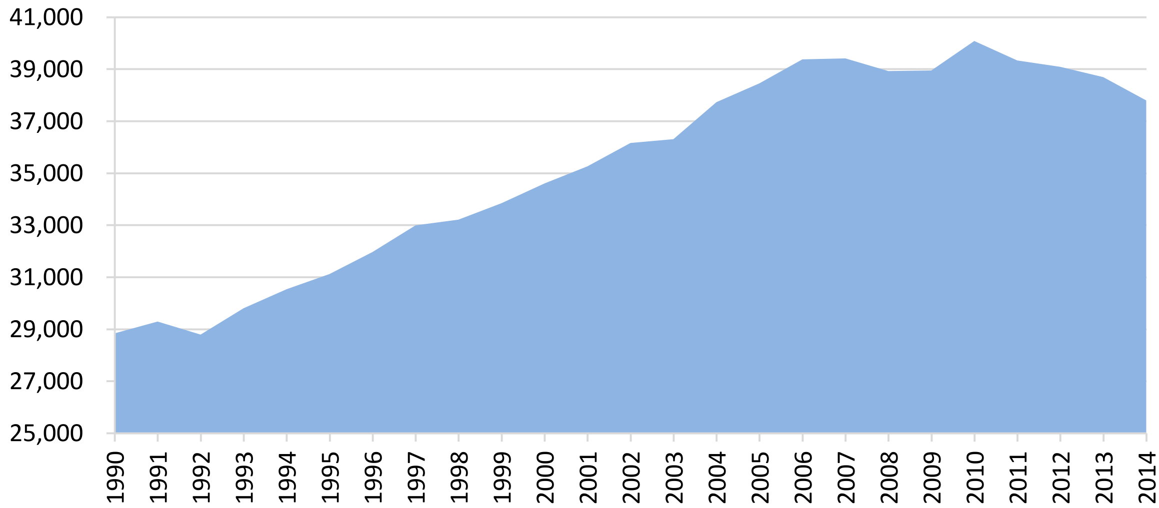
- Responding in a commercially disciplined manner to these supply and demand conditions, electricity companies and developers have, since around 2012, terminated or deferred indefinitely a significant number new generation projects that were announced during the earlier boom period. As Transpower notes in its 2014 Annual Planning Report, there were no committed new grid connected generation projects.

7.3 Change in demand: 2001 to 2014

As occurred in Westpower's region, electricity demand in New Zealand grew reasonably strongly between 2001 and 2010.[151] However, as in Westpower's region, demand for electricity in New Zealand has declined since 2010. This is shown in the chart below.

Figure 19: NZ electricity consumption since 1990 (GWh)

Sources: MBIE's Electricity Data Tables; Electricity Authority's EMI data reports (Grid Demand Trends)



In March 2014, Edison Research described the trends in key components of national demand as follows:

> "Until the global financial crisis (around 2008), electricity demand growth in New Zealand was running at a 10-year average of 1.8% per year. However, since 2010 demand has fallen by over 1,000MWh per year (-2.5%) and is expected to register another fall in 2014. Most of the drop in demand has come from industrial sectors such as wood, paper manufacturing, chemicals and basic metals. Per-household residential demand has also fallen 2.7% over the same timeframe".[152]

[151] In 2010, grid electricity demand peaked close to 39 TWh per annum - MBIE's "New Zealand Energy Outlook: Electricity Insight" at page 7 http://www.med.govt.nz/sectors-industries/energy/energy-modelling/modelling/new-zealands-energy-outlook-electricity-insight

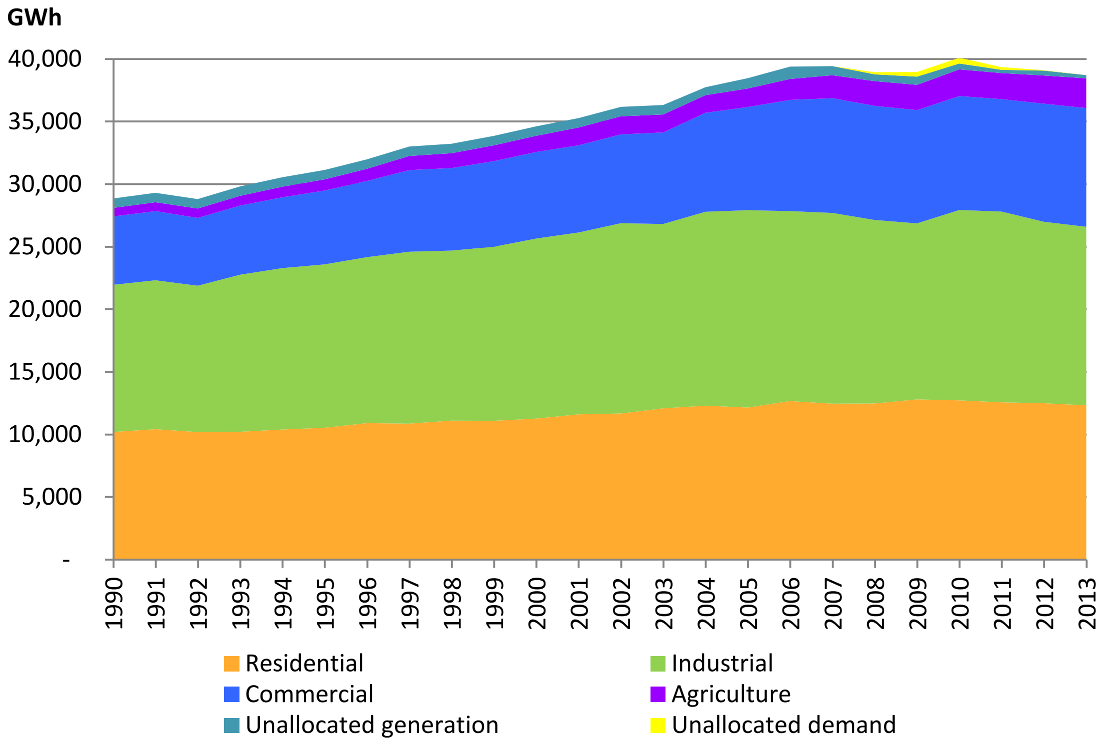
[152] Edison Investment Research, March 2014 - https://nzx.com/files/static/cms-documents/edison-genesis-research.pdf

Transpower notes in its 2014 Annual Planning Report at page 28 that:

> "While peak demand (GW) has only flattened over the last six years, energy demand (GWh) has been relatively flat over the last nine years compared to the strong growth seen in earlier decades. In recent years energy demand has been affected by the:
> — global recession, reduced industrial demand (e.g. Tiwai Aluminium Smelter and Norske Skog Tasman mill),
> — the Christchurch earthquakes
> — increased uptake of energy efficiency lighting and appliances
> — increases in generation embedded within distribution networks which reduce the demand observed at grid exit points."

The most recent New Zealand Energy Quarterly published by MBIE in March 2015 shows that national electricity consumption reduced by 5.9% in the three months from September 2014 to December 2014 relative to the previous quarter. National consumption as at December 2014 has not increased relative to December 2009.[153]

Figure 20: NZ electricity consumption by sector.
Source: MBIE



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[153] New Zealand Energy Quarterly, December 2014 Quarter, released by MBIE on 26 March 2015

7.4 Change in supply capacity: 2001 to 2014

On the supply side in New Zealand, a large amount of new generation capacity (about 2,207 MW) was built between 2001 and 2014 – equal to about 27%% of total capacity in 2001.[154] Of the new capacity added, around 25% of it is base load geothermal capacity, 44% thermal and 27% wind.

As noted in the latest New Zealand Energy Quarterly, geothermal electricity generation contributed more electricity than gas generation in the December quarter 2014 — this is the third consecutive quarter this has happened. Geothermal generation for the 2014 calendar year was also higher than gas generation. This is the first time since 1975 that this has happened.[155]

In the same 14 year period of 2001 to 2014, some less efficient thermal generation was retired or decommissioned. The result has been a net increase in New Zealand's generation capacity of about 16%.[156]

In addition, Transpower completed several major upgrades of transmission capacity at a reported cost of around $2 billion[157], including: [158]

— the North Island Grid Upgrade, boosting transmission capacity between Whakamaru and Auckland;

— the North Auckland and Northland grid upgrade (primarily consisting of the installation of a 220kV underground cable from Pakuranga to Albany); and

— HVDC Pole 3, raising HVDC capacity to 1,000MW in Stage I and 1,200MW upon completion of Stage II. Among other things, this means electricity can flow relatively freely between the North and South Islands in both directions, transporting electricity from its generation source to where it may be needed.

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[154] Electricity Authority – EMI data – http://www.emi.ea.govt.nz/

[155] New Zealand Energy Quarterly, December 2014 Quarter, released by MBIE on 26 March 2015

[156] MBIE – Data Tables for Electricity (to year end 2013) – Table 8 – adding in 2014 new generation of Te Mihi (Contact) and Mill Creek (Meridian) - http://www.med.govt.nz/sectors-industries/energy/energy-modelling/data/electricity

[157] http://www.stuff.co.nz/business/industries/8371840/Transpowers-projects-could-push-up-power-bills

[158] Electricity Authority – "Electricity market performance: 2010–2011 in review – the year to 31 October 2011", at page 34

Figure 21: Total generation capacity in New Zealand (excluding co-generation).
Source: MBIE

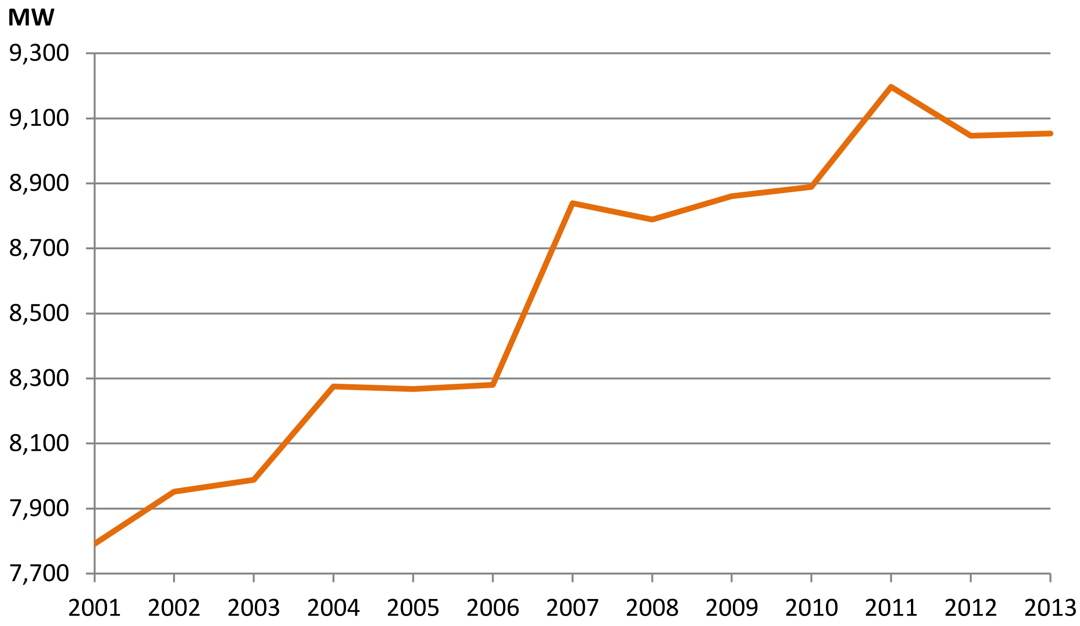
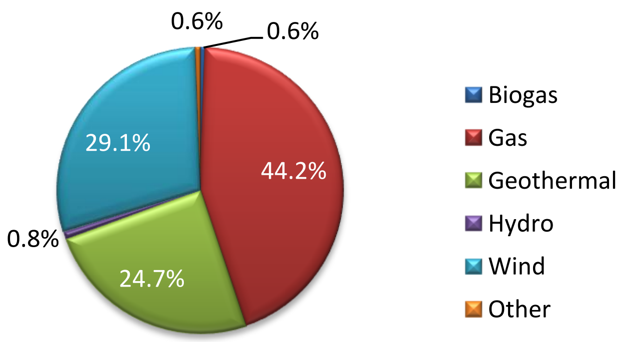


Figure 22: Types of new generation since 2003.
Source: Derived from Electricity Authority data (see table below)



7.5 Net surplus of capacity relative to demand

The result is a surplus of supply relative to demand. As stated in the 2014 report of the Security and Reliability Council:

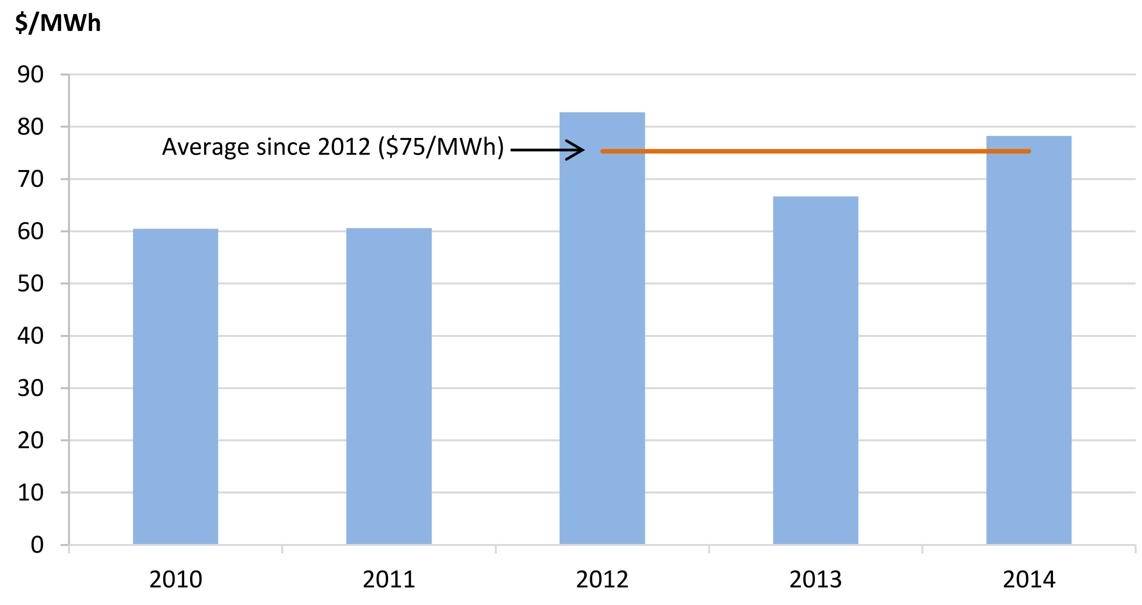
> "Assessed against the security standards set by the Electricity Authority, the New Zealand electricity system is currently oversupplied in generation following recent generation investment. This was likely in part due to recent low demand growth".[159]

[159] Security and Reliability Council, "The system operator's annual assessment of security of supply", 28 May 2014, at bottom of page 6

7.6 Wholesale electricity prices: 2010 to 2014

Reflecting this capacity surplus, the trend in wholesale electricity prices over the last few years has been flat, even declining somewhat in real terms. The average of wholesale prices since January 2012 has been about $75/MWh.

Figure 23: Annual average of wholesale prices ($/MWh)
Source: Electricity Authority's EMI data resource – simple monthly national average



Expectations in relation to future wholesale electricity prices are discussed in the next section of this report.

7.7 Impact on new generation projects across New Zealand

As Transpower notes in its 2014 Annual Planning Report, there were no committed new grid connected generation projects.

Responding in a commercially disciplined manner to the supply and demand conditions outlined above, electricity companies and developers have, since around 2012, terminated or deferred indefinitely a significant number new generation projects that were announced during the earlier boom period. The table below sets out some examples.

Table 7: Impact of surplus supply on new generation projects across New Zealand

New generation proposal	Size (MW)	Consents	Future of project	Date of decision	Reason
Contact Energy projects:					
Upgrade of Taranaki combined-cycle plant	350		Deferred indefinitely		"Flat demand and increasing geothermal generation" [**surplus supply**]
Tauhara II – geothermal development – "NZ's most attractive new generation option"	250	Consented (Oct 2010)	Delayed		"due to a decrease in the consumption of electricity, the project has been delayed...the market is not right to build the power station, and supply and demand figures suggest that an investment is a good few years away", 20 Aug 2014 [**surplus supply**]
Taheke – geothermal development	240 [160]		Deferred indefinitely	June 2013	"due to market conditions" [**surplus supply**]
Waitahora – wind development (Danniverke)	156 - 177	Consented (Dec 2010)	Deferred indefinitely	Aug 2013	
Hauauru ma raki – wind development (Port Waikato)	504	Consented (May 2011)	Cancelled	Aug 2013	"due to the current supply and demand outlook and the competitiveness of the Tauhara II geothermal development" [**surplus supply**]
Might River Power projects:					
Puketoi Range – wind development	310		Deferred indefinitely	June 2013	

Two other projects put on hold are the hydro generation options at the Lake Hawea control gates (Contact Energy), and on the Lake Pukaki canal (Meridian). As MBIE noted in its publication "Energy in New Zealand 2013" at page 65:

[160] NZ Geothermal Association - http://www.nzgeothermal.org.nz/geo_potential.html

> "...construction of new generation is expected to be halted until it is economically viable to build. The Waitaki River Hydro Scheme is an example of this, with the project put on hold until new generation is needed"

Further, in 2013, Genesis Energy put into long term storage a 250 MW coal-fired unit at Huntly a year earlier than anticipated. It also announced that a coal-fired unit would be fully decommissioned. This reduced the capacity of the coal-fired steam turbines at Huntly to 500 MW.

Also in 2013, Contact Energy announced it was likely to reduce the use of its gas-fired combined-cycle plant at Stratford and thereby delay the need for maintenance. In each case, the reason given was flat demand and increased geothermal generation.[161]

7.8 Impact on small hydro proposals – Network Tasman

This outlook of surplus supply and weak demand growth has impacted on all market participants, including small players like Westpower.

An example is Network Tasman, a trust-owned lines company covering the Tasman region, cancelling its proposed 30 MW hydro scheme on the Matakitaki River, near Murchison. Network Tasman's hydro proposal was announced in October 2008, when electricity demand appeared to be growing strongly. However, in December 2013, the project was put on hold indefinitely "due to dramatic changes in electricity use over the previous three or four years, and a predicted decline in future use". As the chief executive of Network Tasman explained:

> "The situation in New Zealand with generating capacity has changed dramatically. Demand is static, if not declining. Comalco [aluminium smelter] may close in the next five years and the prospect of any hydro scheme being built on that Murchison site was economically a long way off" [162]

The reason he gave for the decline in electricity use included increased energy efficiency, more efficient lighting, appliances and home insulation and higher power pricing". As outlined above and below, this is consistent with a widely-held consensus view in the electricity industry.

7.9 Details of new generation built: 2003 to 2014

Details of the new generation added since 2003 is set out in the Table below, which is grouped into embedded and grid-connected sections.[163]

[161] Transpower's 2014 Annual Planning Report, section 5.2.3. See also Electricity Authority: "2013 review of electricity market performance" at page 7 "http://ar2013.publications.ea.govt.nz/Executive+summary/Impacts+on+the+wholesale+market

[162] http://www.stuff.co.nz/nelson-mail/news/9494052/Matakitaki-River-dam-shelved

[163] The 2009 Ministerial Review (Volume 1, para 56) found that: "Analysis of investment in new generation capacity...indicates that investments in new capacity have been least-cost, timely and located sensibly. The least-cost

Table 8: New generation capacity in New Zealand since 2003.
Sources: Electricity Authority

New grid-connected generation capacity in New Zealand since 2003:

Station name	**Fuel type**	**Owner**	**Connection type**	**Capacity (MW)**	**Date**
Watercare Mangere	Biogas	Watercare Services	Embedded	7.0	2003
Christchurch Wind Turbine	Wind	Orion	Embedded	0.5	2003
Tararua Stage 2	Wind	Trustpower	Embedded	36.3	2004
Horotiu Landfill	Biogas	Green Energy	Embedded	0.9	2004
Auckland District Hospital	Gas	Auckland DHB	Embedded	3.6	2005
Pan Pac	Woodwaste	Pan Pac Forest Products	Embedded	12.8	2005
Southbridge Wind	Wind	Energy3	Embedded	0.1	2005
White Hill	Wind	Meridian Energy	Embedded	58.0	2007
Deep Stream	Hydro	Trustpower	Embedded	5.0	2008
Kawerau - KA24	Geothermal	Geothermal Developments	Embedded	8.3	2008
Mangapehi	Hydro	Clearwater Hydro	Embedded	1.6	2008
Tirohia Landfill	Biogas	H.G. Leach & Co.	Embedded	1.0	2008

options for new supply appear to have been selected, and developers have faced strong pressures to build their projects on time and within budget”

Matawai	Hydro	Clearwater Hydro	Embedded	2.0	2009
Mangahewa	Gas	Todd Energy	Embedded	9.0	2009
Hampton Downs Landfill	Biogas	EnviroWaste	Embedded	4.0	2009
Horseshoe Bend Wind	Wind	Pioneer Generation	Embedded	2.3	2009
Chathams Wind	Wind	CBD Energy	Embedded	0.5	2010
Cleardale	Hydro	MainPower	Embedded	0.9	2010
Talla Burn	Hydro	Talla Burn Generation	Embedded	2.6	2010
Te Huka	Geothermal	Contact Energy	Embedded	23.0	2010
Weld Cone Wind	Wind	Energy3	Embedded	0.8	2010
Mount Stuart	Wind	Pioneer Generation	Embedded	7.7	2011
Lulworth Wind	Wind	Energy3	Embedded	1.0	2011
Mahinerangi	Wind	Trustpower	Embedded	36.0	2011
Marsden Diesel	Diesel	Trustpower	Embedded	9.0	2011
Te Uku	Wind	WEL/Meridian Energy	Embedded	64.4	2011
Kawerau - TOPP 1	Geothermal	Norske Skog Tasman	Embedded	25.0	2012
Rochfort	Hydro	Kawatiri Energy	Embedded	4.2	2013
Total new embedded generation				**327**	

New grid-connected generation capacity in New Zealand since 2003:

Station name	**Fuel type**	**Owner**	**Connection type**	**Capacity (MW)**	**Date**
Huntly p40	Gas	Genesis Energy	Grid	48.0	2004
Whirinaki	Diesel	Contact Energy	Grid	155.0	2004
Te Apiti	Wind	Meridian Energy	Grid	90.8	2004
Mokai	Geothermal	Tuaropaki Power	Grid	40	2005
Wairakei Binary	Geothermal	Contact Energy		14	2005
Southdown OCGT	Gas	Mighty River Power	Grid	50	2006
Mokai expansion	Geothermal	Tuaropaki Power	Grid	17	2007
Huntly e3p	Gas	Genesis Energy	Grid	400.0	2007
Tararua Stage 3	Wind	Trustpower	Grid	93.0	2007
Kawerau Geothermal	Geothermal	Mighty River Power	Grid	100.0	2008
Ngawha II	Geothermal	Tai Tokerau Trust / Top Energy	Grid	15	2008
Ohaaki expansion	Geothermal	Contact Energy	Grid	23	2008
West Wind	Wind	Meridian Energy	Grid	143.0	2009
Nga Awa Purua	Geothermal	Mighty River Power	Grid	138.0	2010
Kowhai	Hydro	Pioneer Generation	Partially embedded	1.9	2010

Te Rere Hau	Wind	New Zealand Wind Farms	Partially embedded	48.5	2011
Stratford Peaker	Gas	Contact Energy	Grid	200.0	2011
Ngatamariki	Geothermal	Mighty River Power	Grid	82.0	2013
McKee	Gas	Todd Energy	Grid	102.0	2013
Te Mihi[164]	Geothermal	Contact Energy	Grid	159.0	2014
Mill Creek	Wind	Meridian Energy	Grid	60.0	2014
Total new grid-connected generation				**1,880**	
TOTAL NEW GENERATION SINCE 2003				**2,207**	

[164] Te Mihi is to replace production by Contact's Wairakei power station which is assumed to decrease capacity from 150MW to 109.5MW following the introduction of Te Mihi, partially offsetting the increased capacity from Te Mihi

8. Supply and demand outlook for New Zealand

8.1 Outline of this section

This section 8 is divided into the following parts:

- Summary of key points
- Demand outlook
- Future of Tiwai smelter
- Drivers
- Price indicators
- Future prices
- Conclusion on future prices

8.2 Summary of key points

The key points of this section 8 are as follows:

- The outlook for growth in electricity demand in New Zealand remains relatively weak. In MBIE most recent draft base case, electricity demand grows at 1.1% per annum compared with GDP growth of 2.0%. Most GDP growth comes from the less energy intensive commercial sector. This outlook is relatively unchanged since MBIE's outlook as at 2012, which also projected a base-case scenario of growth at just 1.1% per year

- In terms of fundamentals, the supply situation is still adjusting to the large increase in geothermal generation over recent years and the decline in demand. Some reduction in thermal generation is likely to be required.

- Demand in the last 12 months was 2.1% higher than the preceding 12 months; however growth is still expected to be lower than seen historically, which has clear implications for new generation.

- The medium term outlook is exacerbated by the uncertainty relating to the future of the Tiwai aluminium smelter. There is a strong view that it is likely to reduce the volume of electricity it purchases from Meridian by 172MW. MBIE's modelling indicates that electricity demand would require 9 years to recover if Tiwai closed.

- The outlook for wholesale electricity prices indicates that there is no need to build new capacity in the medium term. Current projections of medium to longer wholesale electricity prices are outlined below.

8.3 Demand outlook

The outlook for growth in electricity demand in New Zealand remains relatively weak. MBIE has recently released its latest Draft Electricity Demand and Generation Scenarios, which is dated 2 April 2015. Under its draft base case, electricity demand grows at 1.1% per annum compared with GDP growth of 2.0%. Most GDP growth comes from the less energy intensive commercial sector. MBIE notes that:

> "The average projected GDP growth rate in the Mixed Renewables scenario [the base case] is 2.0% per annum, but electricity demand growth is only 1.1% per annum. This is explained by two effects. The first and most important is that 80% of the assumed economic growth takes place in the commercial sector, which is less energy intensive. This means that the economy will be increasingly weighted towards lower energy intensive sectors, resulting in lower overall intensity. The second is that in general, energy is used more efficiently because of improvements in technology."[165]

This outlook is relatively unchanged since MBIE's outlook as at 2012, which also projected a base-case scenario of growth at just 1.1% per year:

> "...the average growth in gross domestic product over the next 30 years is less than the rapid growth seen from 1990 to 2004. On top of this, over 80% of the assumed economic growth takes place in less energy intensive service sectors. Combined with continued energy efficiency improvements, these factors explain why electricity demand grows at a slower rate than in the past."[166]

This view is also reflected in the forecasts of the Security and Reliability Council and Transpower.[167]

Its Draft Electricity Demand and Generation Scenarios dated 2 April 2015, MBIE outlines a range of scenarios. In the Mixed Renewables scenario (which is the draft base case), total grid electricity demand is projected to grow at an average of 1.1% per annum. This compares with 1.3% and 0.7% in the High Growth and Low Growth scenarios respectively.[168]

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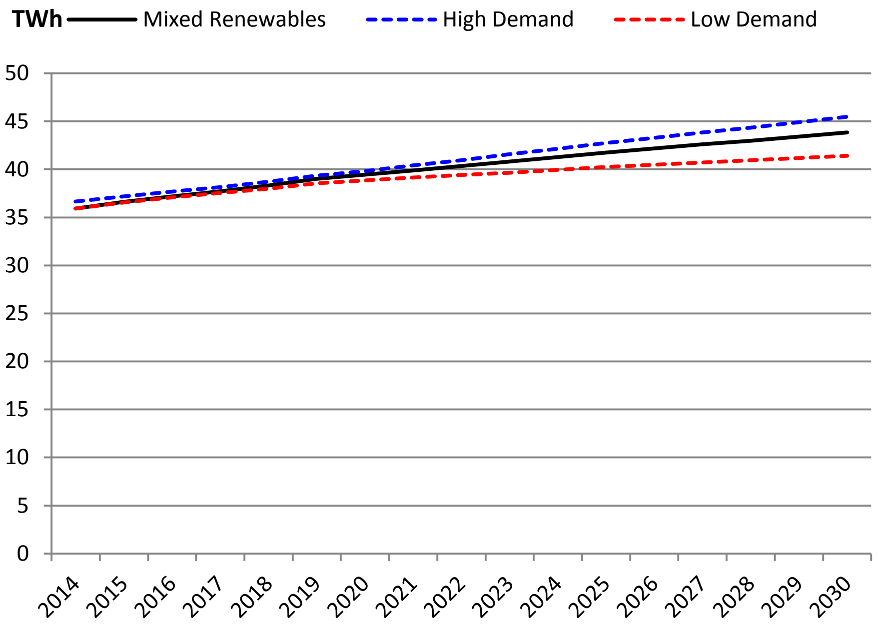
[165] Draft Electricity Demand and Generation Scenarios - Consultation Guide - 2 April 2015", paras 182-183, page 45

[166] MBIE – "New Zealand Energy Outlook: Electricity Insight" (as at 2012) at page 7

[167] 1.1% pa is the mid-range scenario in Security and Reliability Council 2014 report (above) at page 15; MBIE's "New Zealand Energy Outlook: Electricity Insight" (as at 2012) at page 7.

[168] Note that with effect from its 2015 draft scenarios, MBIE's Electricity Demand and Generation Scenarios will not include regional or prudent peak demand projections (although each EDGS scenario will have expected peak demand projections associated with it at the island level). Transpower prepares regional peak demand projections and prudent peak demand projections for transmission planning purposes.

Figure 24: MBIE's draft 2015 demand scenarios.
Source: MBIE



The main electricity companies in New Zealand have expressed similar sentiment. For example, Meridian Energy notes in its 2014 Annual Report:

> "...we are planning on the basis of a relatively flat demand scenario for the medium term" [169]

In its Investor Day presentation of 30 April 2015, Meridian observed that demand in the last 12 months was 2.1% higher than the preceding 12 months; however Meridian is still expecting growth to be lower than seen historically, which has clear implications for new generation.[170]

In half-year results presentation for the six months ended 31 December 2014, Contact Energy notes that no material long-term growth is expected, Tiwai future is uncertain, and continued improvement in energy efficiency is likely. The uncertainty and possible impacts relating to Tiwai are discussed further below.

In terms of fundamentals, the supply situation is still adjusting to the large increase in geothermal generation over recent years and the decline in demand. Some reduction in thermal generation is likely to be required. It would appear that Contact Energy is making adjustments to reduce its thermal fuel commitments, as reflected in Contact Energy's latest Maui gas contract.

[169] Meridian Annual Report for 2014, at page 6

[170] https://nzx.com/files/attachments/212164.pdf

In its half-year results presentation for the six months ended 31 December 2014, Might River Power (MRP) considered that the reduction of 4,000GWh thermal fuel commitments across industry (mainly by Contact Energy) has, in MRP's view, restored the balance of energy demand and supply, and that national demand is back to 2011 levels.

8.4 Future of Tiwai smelter[171]

The medium term outlook is exacerbated by the uncertainty relating to the future of the Tiwai aluminium smelter, which consumes about 13% of New Zealand's total electricity supply. Whether the smelter continues to operate (and, if so, at what level) has yet to be decided.

The owners of the smelter, NZAS, have an option to give notice on 1 July 2015 to terminate their electricity contract with effect from 31 December 2016. It is not clear at this stage whether they will do so. However, even if they do not, NZAS has the right reduce the volume of electricity purchased from January 2017 (reducing the volume by 172MW to 400MW).

If the smelter were to significantly reduce its electricity consumption, or close altogether, it is likely to defer new generation capacity for many more years. Depending on a range of variables, the drop in demand could also lead to a sustained reduction in wholesale electricity prices generally.

In summary, Tiwai's three key options from January 2017 are to:

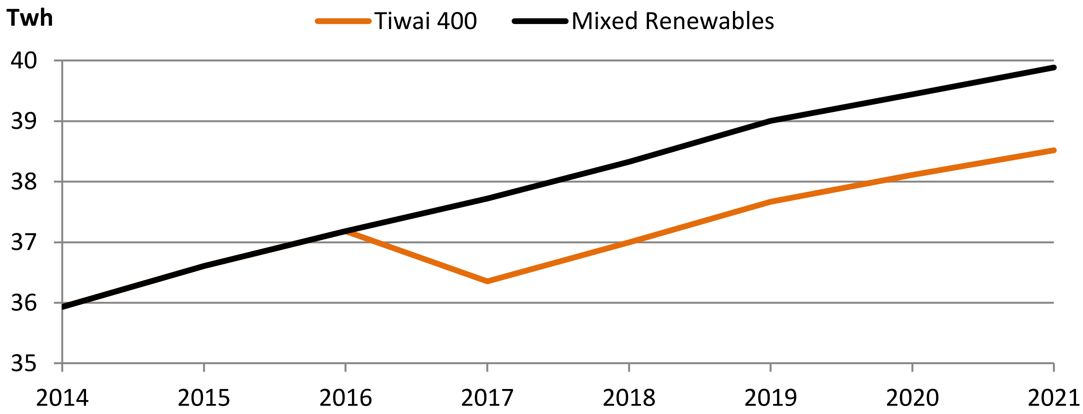
- Reduce the volume of electricity used at the smelter from 572MW to 400MW;
- Keep the volume at 572MW, with 400MW purchased from MEL and 172MW purchased from another generator; or
- Shut the smelter down, with notice given between June 2015 and October 2015.

There is a strong view that Tiwai is likely to reduce the volume of electricity it purchases from Meridian by 172MW.[172] Whether Tiwai buys that 172MW from another generator, or simply reduces the smelter's consumption to 400MW, is not clear at this stage. A general view in the market is that Tiwai's decision on this 172MW component could change wholesale prices by plus or minus $5/MWh.

[171] This section is drawn from Meridian Energy's 2014 Annual Report, and Genesis Energy's IPO prospectus of April 2014 at pages 15 and 37

[172] Woodward Partners, research note, April 2015. First NZ Capital, research note, February 2015

Figure 25: MBIE's Tiwai 400 demand scenario.
Source: MBIE



However, if the smelter were to close, a reduction in wholesale prices, or an equivalent reduction in generation capacity, is likely to be more significantly greater. MBIE's modelling indicates that electricity demand would require 9 years to recover if Tiwai closed.[173]

In its half year report for the six month period ending 31 December 2014, Meridian states in relation to Tiwai (at page 3):

> "At this point, we have no clarity on where NZAS stands on this decision. While it is pleasing to see the New Zealand dollar depreciate against the US dollar, which is positive for the smelter, international aluminium prices have been volatile. However, on our assessment, the plant is in a significantly better financial position than it was at the time the contract was renegotiated in August 2013. On balance, we remain hopeful that the smelter will continue in operation but the decision is not ours. The reality is that uncertainty around the future of the smelter is something the industry just has to live with as NZAS has ongoing termination rights under the contract".

The future of Tiwai is a major factor in any decisions relating to any proposal for new generation capacity.

8.5 Future wholesale electricity prices

8.5.1 Drivers

The wholesale price of electricity trends over the medium to longer term to reflect the unit cost of the next least expensive option for supplying an additional unit of electricity. This is a function of electricity supply relative to electricity demand over time.

[173] "Draft Electricity Demand and Generation Scenarios", 2 April 2015, MBIE

Key factors that influence the level of demand include population size, consumption per household, the strength of the economy in general and in particular sectors (which impacts on commercial and industrial electricity consumption).

Key factors that influence the cost of new electricity supply include the cost and availability of alternative fuels (geothermal, gas and coal in particular), the cost of generation technologies, regulatory factors such as carbon pricing) and decisions on when and which higher cost existing plant is retired.

8.5.2 Price indicators

The publicly available objective indicators of future wholesale electricity prices include:

- MBIE's 2012/13 modelling reflected in its "New Zealand Energy Outlook: Electricity Insight" published in 2013;

- MBIE's 2015 modelling reflected in its "Draft Electricity Demand and Generation Scenarios" dated 2 April 2015;

- Settlement prices for New Zealand electricity futures contracts traded on the Australian Stock Exchange (ASX), recognising that trading of these futures contracts is relatively illiquid beyond the short term;

- Settlement prices for New Zealand hedge contracts traded on the 'Over the Counter' (OTC) market, recognising that trading can be relatively thin;

- Wholesale electricity price projections set out in the assumptions for 'Projected Financial Information' (PFI) in the prospectuses issued for the sale of the Crown's 49% shareholding in Mighty River Power (April 2013), Meridian Energy (September 2013) and Genesis Energy (March 2014); and

- Energy Link provides detailed reporting and forecasting of wholesale prices in its *Electricity and Gas Price Paths* report, the latest available being the October 2013 edition.

Other indications of future wholesale electricity prices are provided by capital markets research institutions that closely follow the prospects of the main electricity companies in New Zealand.

8.5.3 Future prices

Future wholesale electricity prices from the above sources are as follows:

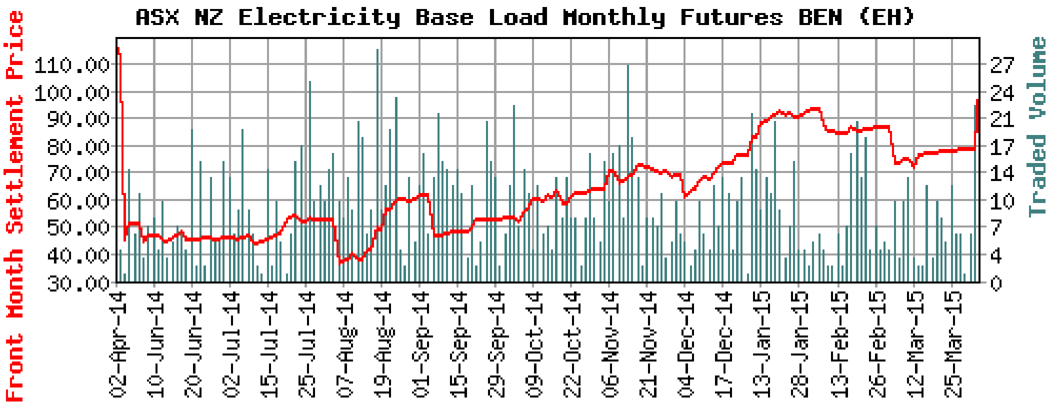
- **Prices in ASX futures market:**
  As at the end of March 2015, the average ASX NZ Electricity Futures price sat at around \$76/MWh, which reflects the markets price expectations over the next three years.[174]

[174] "Draft Electricity Demand and Generation Scenarios", 2 April 2015, MBIE, at para 227, page 55

This is in line with actual average wholesale prices for the last three years (start of 2012 to the end of 2014).

Figure 26: ASX hedge prices

Source: ASX as at 9 April 2015



- **Prices in MBIE's 2012/13 modelling:**
  MBIE's medium growth model in 2013 had wholesale electricity prices rising to $83/MWh (in 2011 dollars) in 2013 and remaining flat until at least 2021.[175] If access to geothermal sites is facilitated, MBIE projected that $83/MWh could continue another year or so. MBIE observed that:

  > "Lower demand growth and excess supply should put strong downward pressure on prices for the next decade".[176]

- **Prices in MBIE's 2015 draft modelling:**[177]
  MBIE's latest draft modelling under all but one scenario has wholesale electricity prices lowering to $75/MWh for 2016 and 2017 (reflecting the average from ASX futures prices), then:

  — Under the draft base case, further lowering to $73/MWh for 2018 and 2019, then rising to $102/MWh in 2021; and

  — Under all other scenarios but one, increasing more gradually and over a longer time-frame.

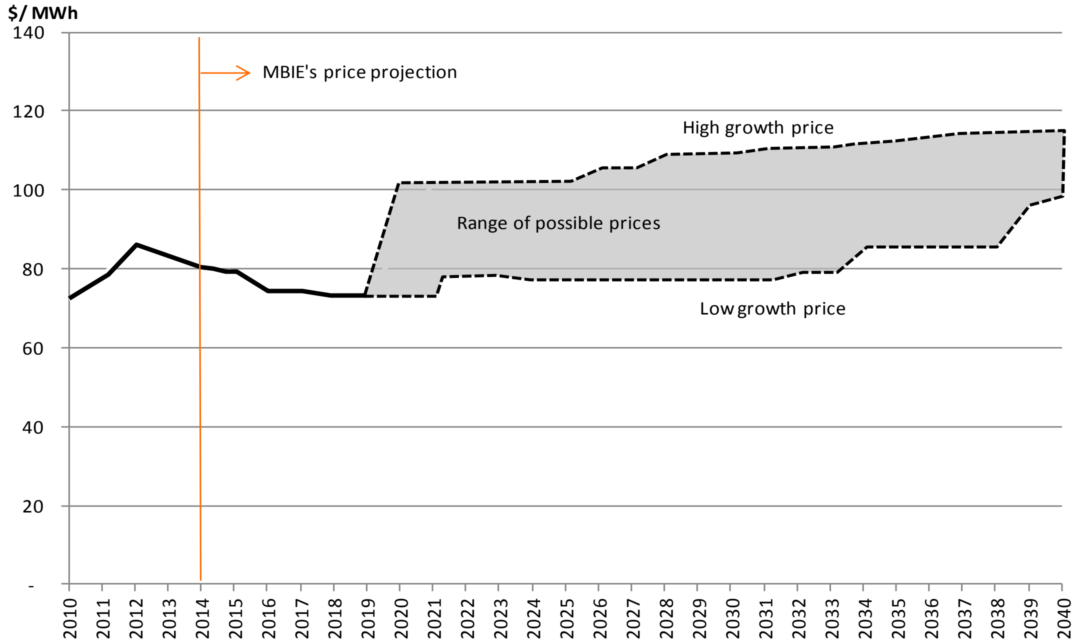
[175] MBIE – "New Zealand's Energy Outlook: Electricity Insight" – see web link above

[176] "New Zealand Energy Outlook: Electricity Insight" (as at 2012/13), MBIE, at pages 1 and 10

[177] "Draft Electricity Demand and Generation Scenarios", 2 April 2015, MBIE, Scenario Summary

— Under MBIE's high growth scenario, prices are projected to rise from $73/MWh in 2019 to $102/MWh in 2020, an increase of nearly 40% in one year. (Based on current information and previous patterns of structural change in medium to longer term wholesale prices[178], this does not seem likely).

Figure 27: Price path forecasts:
Sources: Author using MBIE data



It is important to keep in mind that this modelling is produced by MBIE for a specific regulatory function. It forms part of default scenarios in the "investment test" for approving Transpower's proposals for major capital expenditure under the Commerce Commission's Capital Expenditure Input Methodology Determination of 2012. In short, it becomes one of the parameters that guides Transpower's capital spending, which is a different function from the context in which market analysts project future prices.

- **Prices in Genesis Energy's 2014 prospectus:**
  In the projected financial information section of the Genesis Energy prospectus of March 2014, wholesale prices for 2015 were projected to be $65.50 to $75.50/MWh.

- **Prices forecast by capital markets research institutions:**
  In March 2014, Edison Research observed that:

[178] See 2009 Ministerial Review, Volume 1, Figure 8 at page 40

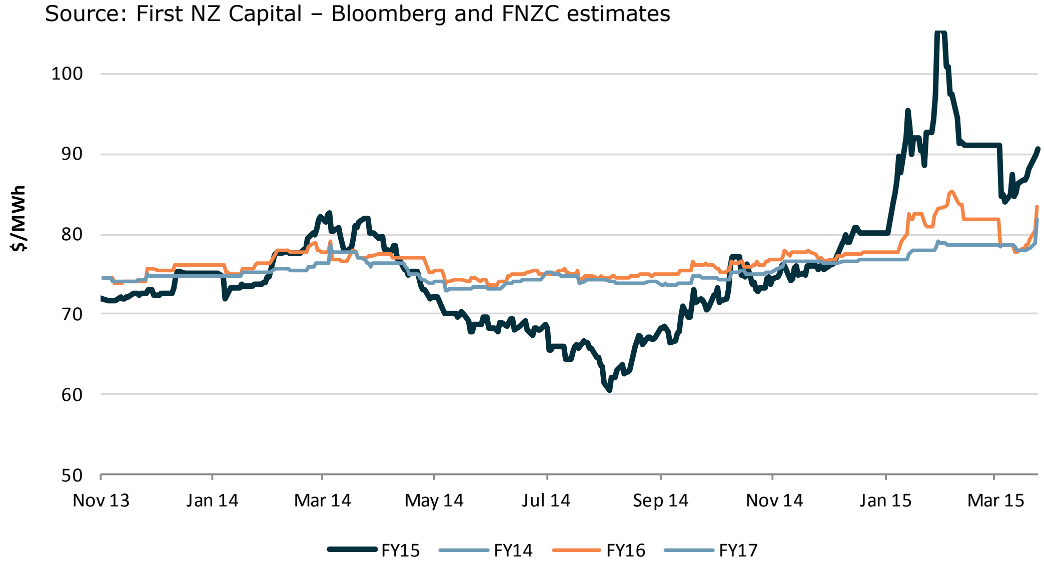
"With the forward curve for wholesale prices looking subdued, the prospects for investment in new generation are unfavourable over the next five years at least...We do not expect any new build in the foreseeable future...There is currently almost 4,700MW of consented projects waiting in the wings".[179]

In February 2015, First NZ Capital outlined in a research note that**:**

"Most oversupply factors currently remain in place. We don't expect additional thermal retirements in the next year; however, we do expect thermal fuel purchases and thermal output to fall significantly. Slight rises in spot prices should result: This seems consistent with current ASX forward price curve. For the first three financial years, our model forecasts use ASX pricing as shown in Figure [28] below. FY15 and 1H16 forward prices have recently risen, reflecting current below average hydro lake storage levels. Contracts for FY17 and FY18 have consistently traded in a nominal $70/MWh to $80/MWh band, tending to reflect medium-term structural expectations rather than influence from current hydro storage".

"...our base case assumes spot prices rise to $80/MWh in real terms by FY25, as shown in Figure [29]. Over the next few years, lower thermal production (particularly lower take-or-pay gas purchases by Contact Energy) will be a main source of slight price firming, as discussed in the next section. Over the medium to long term, we expect a long run trend of increasing demand (500GWh p.a.) will start to drive prices upwards towards the generally accepted long run cost of the next new power station, a geothermal station costing $85/MWh (in real terms)."

Figure 28: Wholesale electricity prices under average of futures contracts for FY14, FY15, FY15 and FY17.
Source: First NZ Capital – Bloomberg and FNZC estimates

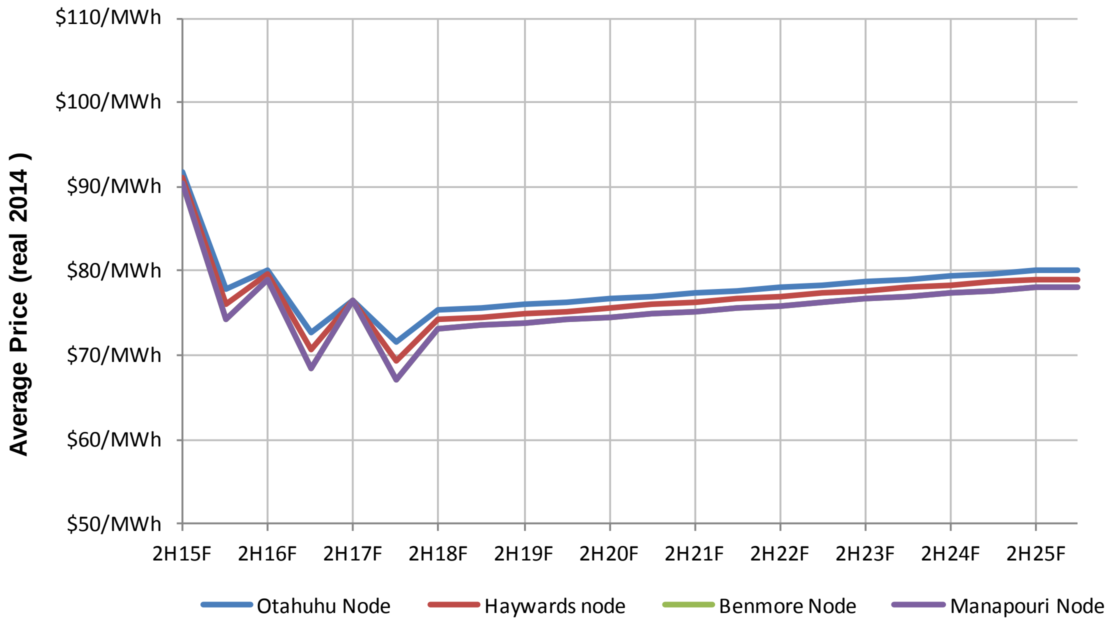


[179] Edison research note https://nzx.com/files/static/cms-documents/edison-genesis-research.pdf

A key observation from the chart above is that prices for forward contracts out to 2017 have remained relatively steady at around $75/MWh since November 2013. The rise around February-March 2015 for FY15 contracts reflects the short duration left on those instruments and the increasing influence of short term (seasonal) hydrology on their price.

Looking beyond 2017, First NZ Capital projects that average wholesale electricity prices will rise to $80/MWh (in 2014 real terms) in the second half of 2024 assuming Tiwai stays open at 400 MW. This is shown in the chart below.

Figure 29: Forecast wholesale electricity prices.
Source: First NZ Capital



The price forecasts of MBIE and First NZ Capital above are in real terms.

8.5.4 Conclusion on future prices

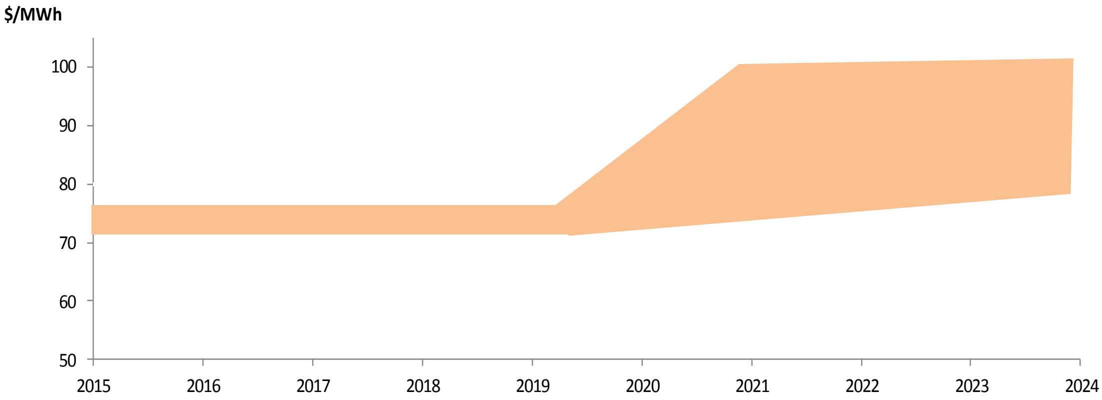
Current projections of medium to longer wholesale electricity prices are as follows:

- Until the end of 2019, average wholesale electricity prices are likely to stay at around $73 to $75/MWh
- Beyond 2019, it is not clear:
  - MBIE's draft base case assumes a rise to $102/MWh in 2021.
  - If there is high geothermal availability, MBIE projects a lower more gradual price path with prices not reaching $100/MWh until 2027.

— Market analysts are projecting a gradual rise from around $75/MWh in 2019 to $80/MWh later in 2025, assuming Tiwai stays open at 400 MW. (If Tiwai continues at 572 MW, price might lift about $5/MWh).

The range of these projections is shown in the chart below. (It is important to keep in mind that, as noted below, MBIE's price assumptions are inputs into Transpower's capital expenditure parameters, which is a different context to that of market analysts' projections).

Figure 30: Current view of future average wholesale electricity prices
Source: Author, MBIE, FNZC



- The future of Tiwai is a material factor that could change the price outlook significantly. Its closure would have a lowering effect on prices and defer new generation.

- As noted in section 5 of this report:

> "...in any market faced with the need to build new capacity (as a consequence of increased demand and the need to replace obsolete capacity) average prices would be expected to track the cost of building new capacity. This is both because such prices provide the incentive needed to build new capacity and because, in a competitive market, all prices trend to the same level"[180]

The current outlook for wholesale electricity prices indicates that there is no need to build new capacity in the medium term.

[180] "Ministerial Review of Electricity Market Performance", Electricity Technical Advisory Group and the Ministry of Economic Development, August 2009, Volume 2, at 239

9. New generation options for New Zealand

9.1 Outline of this section

This section 9 is divided into the following parts:

- Summary of key points
- Projects already consented
- MBIE modelling
- Meaning of full cost or unit cost
- MBIE's LRMC rankings
- MBIE's 2015 draft scenarios
- Choice between competing new generation projects
- Industry consensus on new generation

9.2 Summary of key points

The key points of this section 9 are as follows:

- As noted in section 8 of this report, a large volume of new generation capacity is waiting to be built with consents already obtained. In April 2015, MBIE advised that there is over 4700 MW of generation that has been consented.

- The approximate unit cost of various new generation options under MBIE's modelling is set out below.

- Ideally, the next project to be built should be the one with the lowest total cost (operating, capital and environmental). Decisions by the main market participants since around 2012 to cancel or defer indefinitely new generation projects not already committed show how market and internal commercial disciplines should work. In organisations where those disciplines are not as robust, there is some reason to be concerned.

9.3 Projects already consented

As noted earlier, a large volume of new generation capacity is waiting to be built with consents already obtained:

- As at October 2013, the Electricity Authority records that a total of 4,443 MW of new generation had been consented, with a further 703 MW under consent application or with the consents under appeal.[181] This is more than double the capacity built between 2001 and 2014.

[181] Electricity Authority: "Generation Update – October 2013" – https://www.ea.govt.nz/dmsdocument/11455.

- In May 2014, the Security and Reliability Council identified about 4,582 MW of new projects.[182]
- In April 2015, MBIE advised[183] that there is over 4700 MW of generation that has been consented. The majority of consented generation is wind (over 3000 MW). There is an additional 714 MW of consented renewable generation, including 263 MW of geothermal. There is also 980 MW of consented gas.

In addition to new generation proposals already consented, a large number of options have been scoped for which consents have yet to be sought.

9.4 MBIE modelling

The relative long run cost of these new generation options is modelled by MBIE in its generation cost model. This feeds into MBIE's Electricity Demand and Generation Scenarios for New Zealand (EDGS). Other models used by MBIE in preparing the EDGS include an electricity price forecasting model and a supply and demand energy model.[184]

MBIE's generation cost model "explores how future demand growth might be met. It assumes the cheapest projects are selected first and that sufficient plant must be available to meet both energy demand and peak demand."[185] Projects are ranked from cheapest to most expensive based on their estimated long run marginal cost (LRMC). Lowest cost projects are selected to meet demand growth. The objective of the model is to establish the relativity of costs of generation between the different types of plant.

In general, it only models grid-connected generation. (The model includes the Arnold, Stockton Mine, Stockton Plateau, and Lake Coleridge new generation projects).

Cost and other assumptions relating to each project are set out in a report by Parsons Brinckerhoff ('PB').[186] The cost estimates are based on publically available information, currently available technology and other assumptions such as exchange rates and are the product of a concept or desktop level of estimation. The PB report used a target 'concept' level of accuracy for the cost estimates of ±30 per cent. As PB notes in its report (at page xii): "This level of estimation accuracy supports the Report's objective to provide indicative

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[182] Security and Reliability Council, "The system operator's annual assessment of security of supply", 28 May 2014 at section 9.3

http://www.ea.govt.nz/search/?q=NZ+Security+and+Reliability+Council+%E2%80%93+The+system+operator%E2%80%99s+annual+assessment+of+security+of+supply%2C+as+at+28+May+2014+&s=&order=&cf=&ct=&dp=&action_search=Search

[183] "Draft Electricity Demand and Generation Scenarios Consultation Guide — 2 April 2015", MBIE, para 64, page 20

[184] "Draft Electricity Demand and Generation Scenarios Consultation Guide — 2 April 2015", MBIE, para 101, page 27

[185] See http://www.med.govt.nz/sectors-industries/energy/energy-modelling/modelling/new-zealands-energy-outlook-electricity-insight/interactive-electricity-generation-cost-model. As noted in section 5, however, LRMC also has a more specific definition.

186 "2011 NZ Generation Data Update", 26 January 2012, Parsons Brinckerhoff http://www.med.govt.nz/sectors-industries/energy/energy-modelling/technical-papers/2011-nz-generation-data-update. Parsons Brinckerhoff is a multinational engineering and design firm operating in the fields of strategic consulting, planning, engineering, construction management, and infrastructure/community planning-https://www.pbworld.com/#

estimates which help the MED establish the relativity of costs of generation between the different types of plant".

MBIE recently issued its "Draft Electricity Demand and Generation Scenarios: Consultation Guide — 2 April 2015", which sets out MBIE's current draft views on a range of key assumptions and variables, including new generation.

As noted earlier, it is important to keep in mind that this modelling is produced by MBIE for a specific regulatory function. It forms part of default scenarios in the "investment test" for approving Transpower's proposals for major capital expenditure under the Commerce Commission's Capital Expenditure Input Methodology Determination of 2012. In short, it becomes one of the parameters that guide how much, when and where Transpower spends on the transmission grid. It is not a tool that evaluates the viability of specific projects or when they should be built.

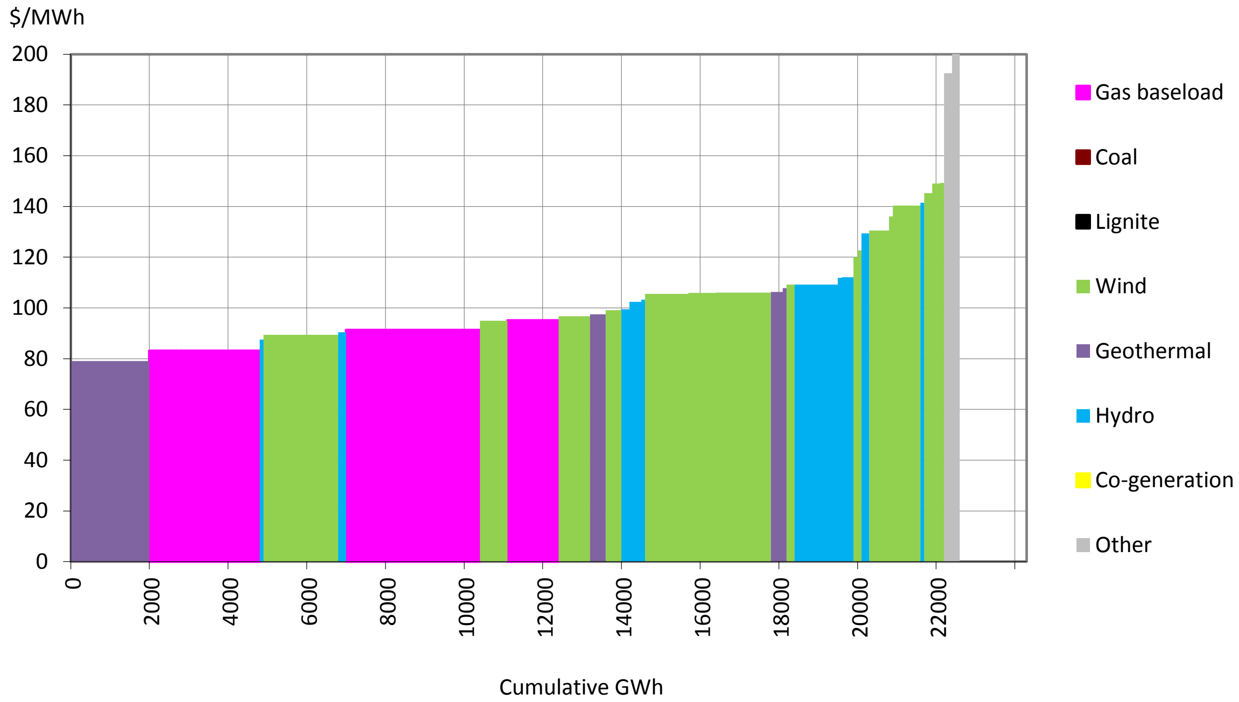
9.6 Meaning of full cost or unit cost

As noted in section 5 of this report, unit cost is the wholesale electricity price a generator needs to earn, on average, in order to recover capital and operating costs and earn an economic return on investment. MBIE uses this as their definition of LRMC.[187] Put another way, "risk-averse investors require recovery of capital costs with a suitable premium for risk, as well as the fixed and variable operating costs they incur in operations".[188] It does not include retailer costs and margins and the cost of transmission and distribution.

9.7 MBIE's LRMC rankings

MBIE's LRMC rankings of new grid-connected generation projects using draft base case assumptions are as follows.

Figure 31: LRMC of new non-peak generation ($2013/MWh)
Source: MBIE - Interactive Generation Cost Model



The chart above is based on the following hierarchy of LRMC estimates, which are +/- 30%:

Type	Project	Fully consented	MW	Typical GWh pa	Capital cost $m	Variable O&M, $/MWh	Fixed O&M, $/kW	LRMC $/MWh
Geothermal	Tauhara stage 2	Yes	250	1971	1201	0.00	105.00	79.06
Gas - CCGT	Otahuhu C	Yes	400	2803	610	4.30	35.00	83.04
Hydro	Hawea Control Gates	Yes	17	74	53	0.86	6.38	87.49
Wind	Hauauru ma raki stage1	Yes	252	975	627	3.00	50.00	89.43
Wind	Hauauru ma raki stage2	Yes	252	975	627	3.00	50.00	89.43
Hydro	Lake Pukaki	Yes	35	153	114	0.86	6.38	90.45
Gas - CCGT	Rodney CCGT stage 1	Yes	240	1682	384	4.30	35.00	91.27
Gas - CCGT	Rodney CCGT stage 2	Yes	240	1682	384	4.30	35.00	91.27
Wind	Turitea	Yes	183	708	478	3.00	50.00	94.91
CCGT	PropopsedCCGT1	Proposed	194	1360	333	4.30	35.00	95.01
Wind	Hawkes Bay windfarm	Yes	225	780	560	3.00	50.00	96.68
Geo	Tikitere Lake Rotoiti	Applied	45	355	303	0.00	105.00	97.53
Wind	Project Central Wind	Yes	120	416	314	3.00	60.00	99.05
Hydro	Arnold	Yes	46	201	192	0.85	6.38	99.51
Hydro	Lake Coleridge 2	Applied	70	307	289	0.85	6.38	102.36
Hydro run of river	Stockton Mine	Yes	35	153	135	0.80	6.38	103.24
Wind	Waitahora	Yes	156	541	408	3.00	50.00	105.54
Wind	Puketoi	Applied	159	551	416	3.00	50.00	105.55
Wind	CastleHill stage1	Yes	200	693	513	3.00	50.00	105.97
Wind	CastleHill stage2	Yes	200	693	513	3.00	50.00	105.98
Wind	CastleHill stage3	Yes	200	693	513	3.00	50.00	106.00
Geothermal	Rotoma Lake Rotoma	Applied	35	276	260	0.00	105.00	106.23
Geothermal	Kawerau Te Ahi O Maui	Applied	10	79	76	0.00	105.00	107.81
Wind	Taharoa	Yes	54	209	166	3.00	60.00	109.15
Hydro (SC)	North Bank Tunnel	Applied	260	1139	1045	0.84	6.38	109.21
Hydro run of river	Stockton Plateau	Yes	25	110	106	0.86	6.38	111.78
Hydro run of river	Wairau	Yes	70	307	297	0.70	6.38	112.12

As noted above, the objective of the MBIE's model is to establish the relativity of costs of generation between the different types of plant. It is not an assessment of project-specific readiness.

Note in particular that it is widely agreed that Contact Energy's geothermal development option at Tauhara (stage 2) is the next cheapest new generation option in New Zealand. However, market analysts consider its full cost to be about $85/MWh, not $79 as assumed in MBIE's model above.

9.8 MBIE's 2015 draft scenarios

In its Draft Electricity Demand and Generation Scenarios of 2 April 2015 (EDGS), MBIE outlines eight equally weighted draft scenarios out to 2040. On the demand side, the scenarios range from high to low growth. On the supply side, the scenarios cover high gas availability, high geothermal availability, low carbon emissions, Tiwai closed or Tiwai reduced to 400MW.

Key conclusions from the MBIE's Draft EDGS include:[189]

- **Geothermal:** There is likely to be significant investment in geothermal plants over the next 30 years.[190] At current costs, geothermal plant is relatively cheaper than other technologies. In all scenarios, over 500 MW of geothermal generation is built by 2040.

- **Gas:** Baseload gas plant build depends on the gas and carbon market conditions. In a scenario with cheap plentiful gas we could expect significantly lower wholesale prices.

- **Wind:** A significant amount of wind is also built. Higher levels of wind build may be reached if there is stronger demand growth or reductions in wind costs relative to geothermal.

- **Hydro:** In the draft base case scenario, 545 MW of hydro is built by 2040. This is lower than the wind and geothermal built, but it still remains at 47% of total generation due to high existing capacity. Over 90% of hydro is built in the South Island.

- **Demand-side management:** 476 MW of demand-side management is available to provide capacity for peak demand periods.

- **LRMC of renewables:** Long run wholesale prices would need to rise to around $100/MWh in order for new renewable plant to be economic. In a scenario with cheap plentiful gas we could expect significantly lower wholesale prices.

- **Base case:** In the draft base case:

    — In 2018: the first major investment in new generation plant occurs when 250 MW of geothermal and 100 MW of gas peaker plant are built. This coincides with the retirement of the third Huntly coal/gas unit.

    — In 2024: a new gas baseload plant is required to replace the Taranaki Combined Cycle plant.

    — In 2025: 510 MW of new geothermal generation is built by 2025.

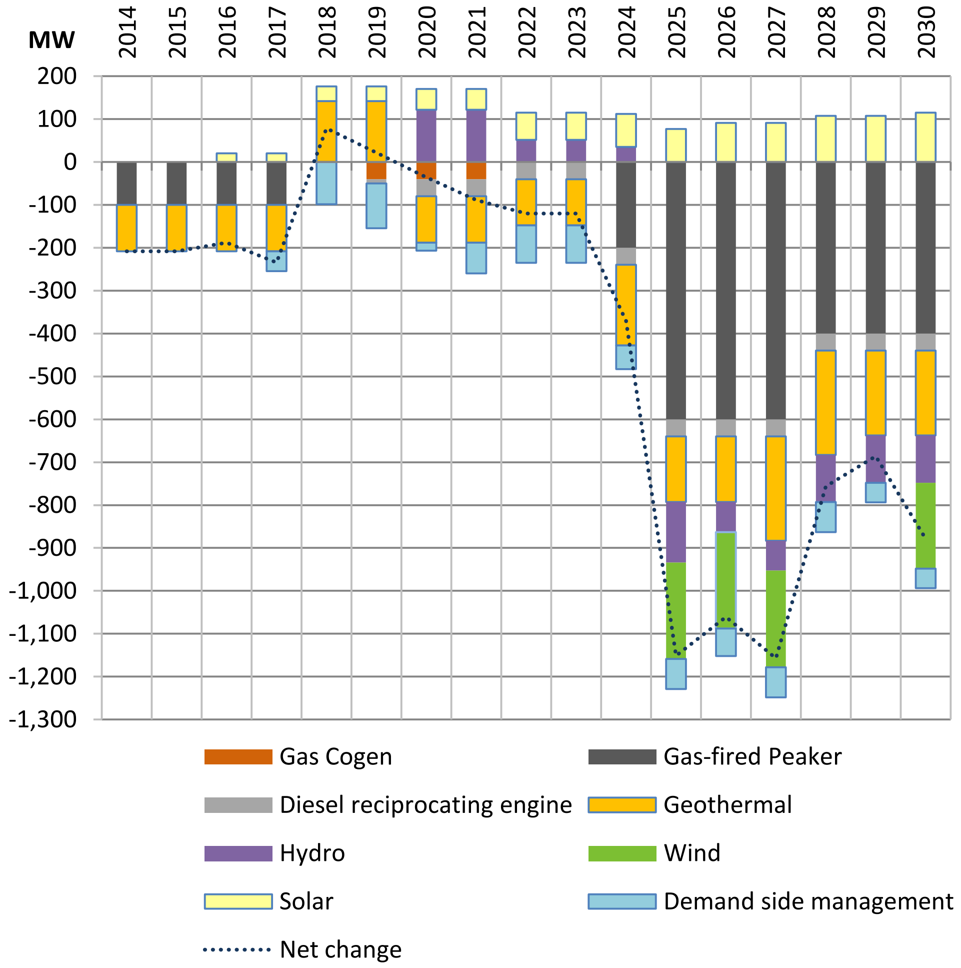
[189] "Draft Electricity Demand and Generation Scenarios: Consultation Guide — 2 April 2015", MBIE, at paras 200 – 228

[190] This is consistent with the MBIE's view in 2013, which was that even if new coal and gas generation options are excluded, new generation supply is expected to continue to come from new geothermal plants over the next 30 years "New Zealand's Energy Outlook: Electricity Insight", July 2013, MBIE, at page 8 - http://www.med.govt.nz/sectors-industries/energy/energy-modelling/modelling/new-zealands-energy-outlook-electricity-insight

— After 2025: 1,169 MW of wind is built. (Geothermal plant generally has a lower LRMC than wind generation, so this tends to be built before wind).

The key changes between MBIE's draft base case in 2015 compared to 2013 are shown in the chart below.

Figure 32: MBIE's Base Case – change from 2013 to 2015
Source: Author using MBIE data



Key changes in from the 2013 to 2015 draft base case scenario include:

- Overall, considerably less new generation is required to meet demand;
- The next new power stations are still geothermal but they are not needed until around 2018 and 2019;
- Gas-fired peaker generation is closed in the next three years;

- The lowest cost hydros – Lake Hawea Control Gates and Pukaki Canal – could come into play around 2020; and

- Solar generation comes in play from around 2016.

9.9 Choice between competing new generation projects

The report of Ministerial Review of Electricity Market Performance in 2009 noted that:

> "It is important to minimise the costs of new generation, get the right generation built, and ensure that alternatives such as energy efficiency are fully exploited" [191]

Obviously, the order of building new generation does not follow a stylised cost stack in a generation expansion model. Which new generation project is built next should be a function of robust competition between competing parties operating in a commercial manner and responding to efficient resource allocation disciplines within environmental parameters set by consent and concession authorities.

Ideally, the project with the lowest total cost (operating, capital and environmental) should win. Decisions by the main market participants since around 2012 to cancel or defer indefinitely new generation projects not already committed show how market and internal commercial disciplines should work.

In organisations where those disciplines are not as robust, there is some reason to be concerned.

9.10 Industry consensus on new generation

As outlined in section 7.7 of this report, most electricity companies have responded in a commercially rational manner to the gap between the cost of new generation options and expected wholesale electricity prices over the medium term. There is a general consensus that new generation is not required for some time. This is reflected in statements by the key players:

- **Trustpower** states in its 2014 Annual Report: "...the current supply and demand outlook indicates it may be five years or more before New Zealand requires new generation"

- **Mighty River Power** announced on 7 June 2013 that that it is unlikely to start any new generation projects in the next three to five years, due mainly to an over-construction of gas, wind and geothermal power stations over the past decade. [192] As BMI noted: "We believe Mighty River's announcement...indicates a situation of oversupply in the market

[191] "Ministerial Review of Electricity Market Performance", Electricity Technical Advisory Group and the Ministry of Economic Development, August 2009, Volume 1, para 54

[192] Business Monitoring News and Views

which is unlikely to be resolved anytime soon...we still expect a comfortable buffer in electricity supply over demand to be maintained over the coming years, even after Mighty River's decision to delay development of its projects.” [193]

- **Contact Energy** re-emphasised in its half year results announcement on 16 February 2015 that: “The New Zealand electricity market is mature with no material growth in electricity demand expected and risks around the future of the Tiwai aluminium smelter and continued erosion of retail margins.” [As an aside, it is interesting to note that this concern that the market is “mature with no material growth in...demand expected” is parallels the a central concern for Ian Dickson & Associates in their review of the Riverstone Holdings/monorail business proposal, which found at page 25 of their report: “The biggest challenge is the size of the potential market...actual experience in recent years suggests the market for Milford-bound visitors is mature”]

[193] http://www.businessmonitor.com/news-and-views/oversupply-in-power-sector-driving-investment-overseas

10. Supply and demand outlook for Westpower's region

10.1 Outline of this section

This section 9 is divided into the following parts:

- Summary of key points
- Electricity demand forecasts for Westpower region:
  - Forecast in Westpower's Waitaha application
  - Inconsistent demand forecasts
  - Demand growth assumptions in Westpower's Waitaha application
  - Westpower's forecast in its 2014 Information Disclosure
  - Transpower's 2014 demand forecasts
  - Inconsistencies in Westpower's 2014 Asset Management Plan
- Sources of demand growth:
  - Overview
  - Dairy outlook
  - Mining outlook
  - Lack of caution in relation to step changes in demand
  - Conclusion on Westpower's demand outlook
- Electricity supply available to Westpower's region:
  - Overview
  - Supply from embedded generation
  - Mix of supply from transmission and embedded generation
  - Capacity of Westpower's substations
- Conclusion on adequacy of supply capacity relative to demand

10.2 Summary of key points

The key points in this section 10 are as follows:

- In its Waitaha application, Westpower forecasts peak demand for electricity in its distribution area to grow from 50 MW in 2012 to 70 – 80 MW by 2030.

- This forecast is not consistent with Westpower's forecast in its statutory Information Disclosures to the Commerce Commission, Transpower's forecast for the West Coast in its 2014 Annual Planning Report or MBIE's national demand growth projection.

- Based on the analysis in this report, and taking into account Westpower's poor track record in forecasting (as outlined in section 6.6 of this report), it is reasonable to conclude that Westpower's long term demand forecast of 70 – 80 MW by 2030 in its Waitaha application is more than questionable and provides no basis for medium term investment in new generation capacity.

- Further, based on current evidence of the medium term outlook, Westpower's forecast step change in peak demand from 48.5 MW in 2014 to 62.7 MW in 2023, with the main growth coming from dairying and mining, would appear to have a low probability of occurring.

- As at 31 March 2014, Westpower's network had an approximately 38 MW surplus in peak capacity. Applying the growth rate in Westpower's 2014 Information Disclosure, it would take about 38 years to use up this surplus.

- As Westpower acknowledges in its 2014 Asset Management Plan, the 2011 transmission upgrade delivered security of supply:

  > "Currently, there is sufficient n-1 transmission capacity available in the transmission network feeding the West Coast, to ensure that major new loads can be supplied on an uninterruptible basis, and so **electricity supply should not be a constraint to future economic development.**" [Emphasis added]

10.3 Electricity demand forecasts for Westpower region

10.3.1 Forecast in Westpower's Waitaha application

Westpower states in its Waitaha application (at page 118):

> "Peak demand for electricity in the Westpower distribution area has been forecast to grow from 50 MW in 2012 to 70 – 80 MW by 2030, whilst electricity consumption is forecast to grow from 300 GWhs to 400 GWhs per annum by 2030. These growth rate forecasts incorporate possible new mining developments and ongoing growth in dairy farming and milk processing. This will increase the reliance on imported electricity via the national grid in the absence of new generating capacity on the West Coast"

No information is provided in the Waitaha application to support this forecast, and the application contains no other information in relation to whether additional generation is needed to meet electricity demand.

Further, Westpower's demand forecast in its Waitaha application is not consistent with its demand forecasts provided to the Commerce Commission or the demand forecasts of Transpower and MBIE.

10.3.2 Inconsistent demand forecasts

There are five reference documents with relevant demand forecasts:

- Westpower's demand projection in its Waitaha application;

- Westpower's demand forecast in its 2014 Asset Management Plan;
- Westpower's forecast in its statutory Information Disclosures to the Commerce Commission[194];
- Transpower's forecast for the West Coast in its 2014 Annual Planning Report; and
- MBIE's national demand growth projection.

The following are reasonably consistent:

- MBIE's national growth projections and Transpower's 2015 forecast for the West Coast are in line with each other; and
- Westpower's forecast in its 2014 Information Disclosures is reasonably close to Transpower's forecast for the West Coast and MBIE's projection for New Zealand.

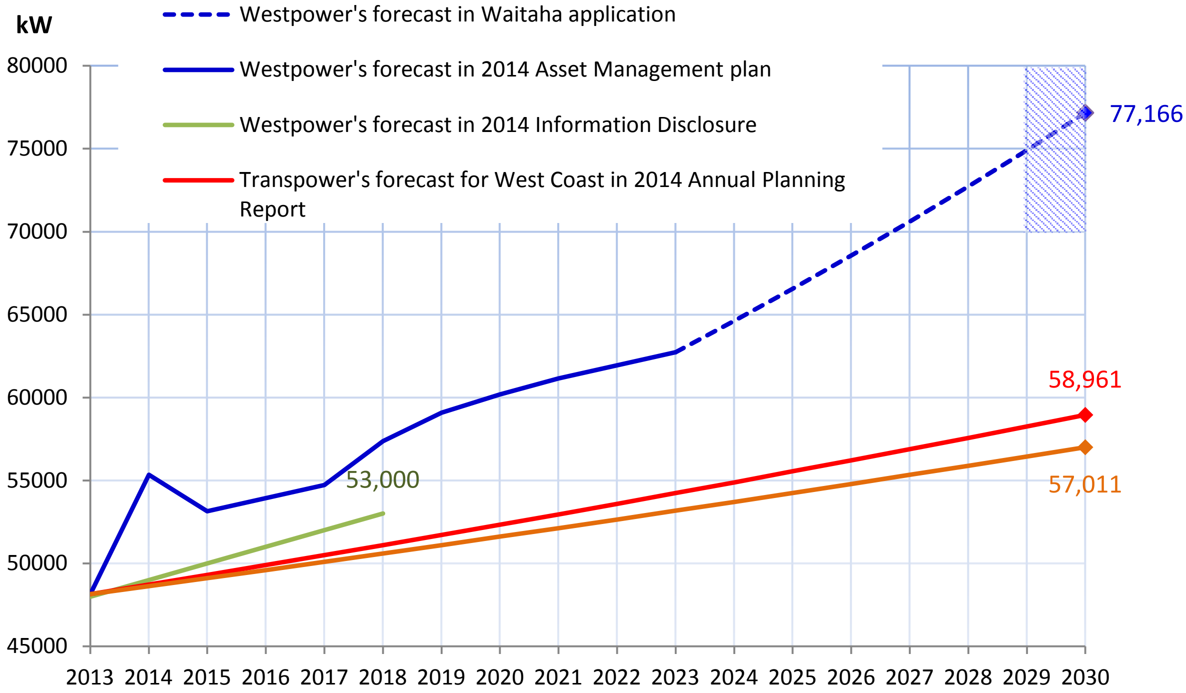
However, there are significant inconsistencies –

- Between Westpower's demand projection in its Waitaha application and Westpower's forecast in its 2014 Asset Management Plan;
- Between Westpower's Waitaha application and Westpower's forecast in its 2014 Information Disclosure to the Commerce Commission;
- Between Westpower's forecasts in its 2014 Asset Management Plan and Transpower's forecast in its 2014 Annual Planning Report; and
- In Westpower's 2014 Asset Management Plan, in which its narrative is not consistent with its numbers relating to expected demand growth.

The major differences are shown in the chart below.

[194] As noted in section 3 of this report, an electricity distribution company, like Westpower, is required by law to file every year with the Commerce Commission schedules of Information Disclosure. The information to be disclosed is prescribed by subpart 9 of Part 4 of the Commerce Act 1986.

Figure 33: Westpower's inconsistent demand forecasts.
Source: Transpower, Westpower, Commerce Commission



The grounds for Westpower's forecast growth of 20 to 30 MW over the next 15 years appear to be extremely weak. Based on the analysis in this report, and taking into account Westpower's poor track record in forecasting (as outlined in section 6.6 of this report), it is reasonable to conclude that Westpower's long term demand forecast of 70 – 80 MW by 2030 in its Waitaha application is more than questionable and provides no basis for medium term investment in new generation capacity.

10.3.3 Demand growth assumptions in Westpower's Waitaha application

To grow from 50 MW in 2012 to 70 – 80 MW by 2030 would require an average growth rate of around 3.5% per year for the next 15 years. In support, Westpower refers to the high demand growth between 2003 and 2011, which it describes as an average rate of 4.32% per year.

However, as outlined in section 6 of this report, demand growth fell significantly from 2010 to 2014. As noted earlier, the cause of the decline was not just to the closure of Pike River Mine. Other large electricity consumers have closed or reduced demand, and smaller consumer demand has, like the rest of New Zealand, remained relatively flat.

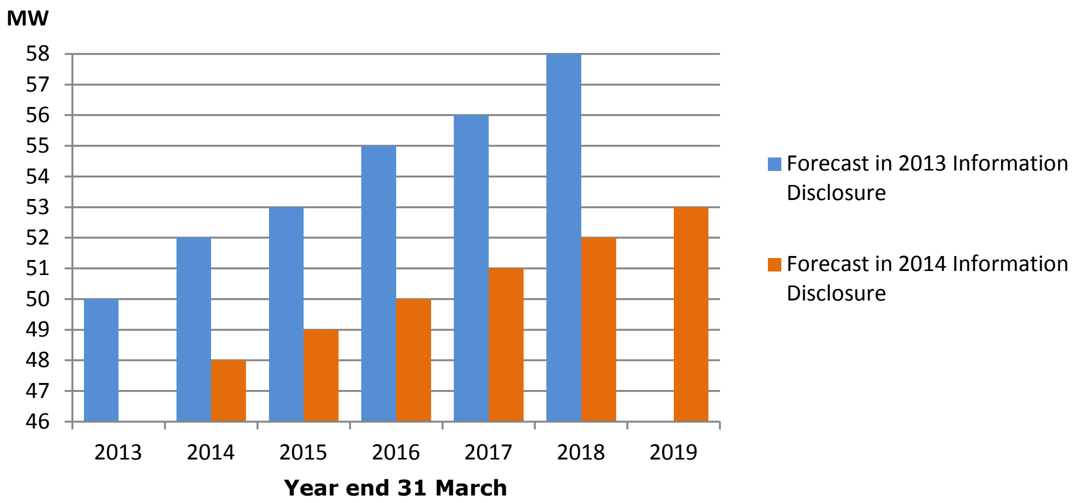
Westpower's claimed growth rate of 3.5% pa for the next 15 years is profoundly inconsistent with the forecasts of MBIE for New Zealand (1.1% pa) and Transpower for the West Coast (1.2% pa). It is also inconsistent with the forecast provided by Westpower to the Commerce Commission in its 2014 Information Disclosure (under 2% pa).

10.3.4 Westpower's forecast in its 2014 Information Disclosure

The Information Disclosure regime requires a lines company to (among other things) forecast peak demand on its network for the next five years. Westpower's 2014 forecast added 1 MW each year for the next five years. This is significantly lower than the forecast in Westpower's Waitaha application. However, it is still higher than Transpower's 2014 forecast for the West Coast.

Interestingly, the forecast in Westpower's 2013 Information Disclosure was quite a lot more bullish, as shown in the chart below. The forecast in Westpower's Waitaha application is more in line with its 2013 Information Disclosure.

Figure 34: Change in Westpower's demand forecast to Commerce Commission.
Source: Westpower's Information Disclosures 2013 and 2014



The chart above shows a clear reduction in forecast demand, however this is not reflected in Westpower's Waitaha application.

10.3.5 Transpower's 2014 demand forecasts

In its 2014 Annual Planning Report, Transpower assumed demand growth on the West Coast of just 1.2% for the next 15 years[195]. Transpower applied the same growth rate as was expected for national demand. Its 2014 forecast was derived using historical data, and modified to account for customer information, where appropriate. The power factor at each grid exit point was also derived from historical data.

Applying Transpower's forecast growth rate of 1.2% (starting with Westpower's peak demand in 2013) results in an increase of about 10 MW for 15 years. This is significantly less than the 20 to 30 MW increase forecast in Westpower's Waitaha application.

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[195] Transpower's 2014 Annual Planning Report, section 16.3, page 241

10.3.6 Inconsistencies in Westpower's 2014 Asset Management Plan

Not only is Westpower's 2014 Asset Management Plan ('AMP') forecast significantly higher than its 2014 Information Disclosure forecast and Transpower's 2014 forecast, Westpower also describes its demand outlook in ways that appear to be inconsistent within its 2014 AMP.

For example, on the one hand, Westpower says peak demand:

> "will remain relatively **flat in the short to medium term** and will increase to around 60 MW by 2022, depending on future economic growth[196]" [emphasis added]

On the other hand, its forecast in 2014 has peak demand:

- Not flat, but rather jumping 15% in the first year; and
- Reaching 60 MW in 2020, not 2022 as they say in their narrative

Growth to 60 MW in 2020 is not exactly "flat in the short to medium term". As noted above, it equates to an annual growth rate over the medium term (7 years) of about 3.5%.

In another example, Westpower acknowledges that:

> "...the Pike River mine disaster, which occurred on 19 November 2010, followed by the sudden and unexpected closure of Solid Energy's Spring Creek Mine near Greymouth in November 2012, has resulted in a major step load decrease of over 10 MW for Westpower, representing some 20% of system load. At this stage, it seems unlikely that either of these loads will come back on stream within the short term or perhaps even over the entire planning period. Consequently the load forecast projections for 2014/15 are necessarily subdued"[197]

However, Westpower's narrative of "subdued demand" does not appear to have been reflected in its forecast numbers for 2014 and 2015.

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[196] Westpower's Asset Management Plan for 2014-2024, section 1.9, page 16; and section 5.4.1 – "It is anticipated that the current ADMD of around 48 MW will increase slightly in the short to medium term, with future load growth driven principally by economic development and activity"

[197] Westpower's Asset Management Plan 2014-2024 – section 5.2, page 125

10.4 Sources of demand growth

10.4.1 Overview

Westpower seems to be relying on significant growth from new mining developments, dairy farming and milk processing to support its forecast growth 3.5% per year for the next 15 years to reach 70 – 80 MW in peak demand by 2030. Westpower claimed in its 2014 Asset Management Plan that:

> "Although the local economy has been significantly impacted by the loss of major mining loads as noted earlier in the plan, the underlying economic activity on the West Coast from other sectors such as the dairy, gold and timber industries is underpinning a relatively stable outlook."[198]

The demand forecast in its 2014 AMP has:[199]

- Westland Milk Products upgrading its plant between 2013 and 2023 requiring an additional 8 – 13 MW;
- Landcorp developing several new dairy farms in the Fox Glacier area over the next five years (now that Westland Milk Products has extended its collection area to include this region); and
- Solid Energy establishing a new open-cast coal mine near Strongman in 2018 requiring an additional 4 MW.

Westpower does not give a probability rating of those three step-change increases occurring. However, based on current indicators of the reasonably foreseeable future, these would seem to be lower probability developments.

10.4.2 Dairy outlook

The bulk of Westpower's forecast growth in electricity demand comes from the dairy industry. Dairy represents about 21% of GDP in Westland.[200] Any increase in electricity demand from dairying depends primarily on future dairy commodity prices. Prices and profitability in the dairy industry are highly variable. For example, as shown in the chart below, the underlying trend line in the Global Dairy Trade Price Index (which reflects international dairy prices) since July 2008 until the present has been remained relatively flat (an increase of 200 points over seven years, adjusted for inflation, is a relatively flat in real terms). There was a year-long period of elevated prices (February 2013 to February 2014), but the index has declined significantly since then.

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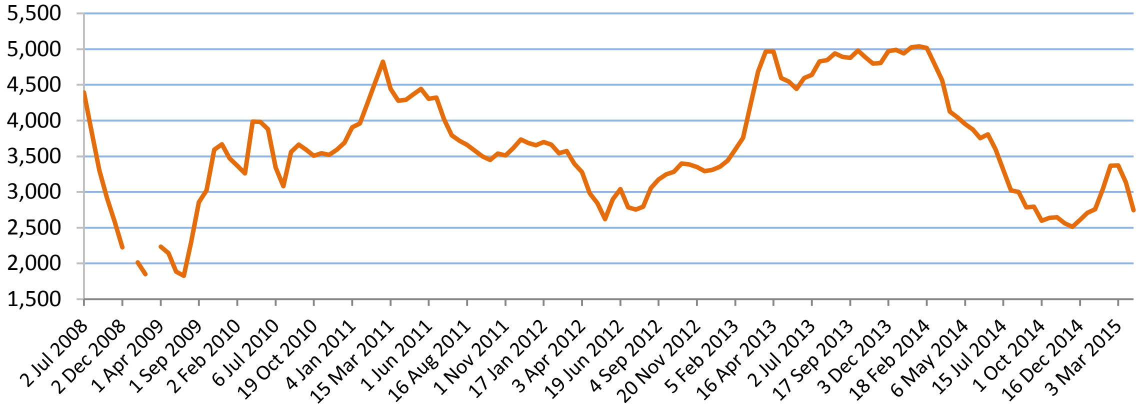
[198] Westpower's Asset Management Plan 2014-2024 – section 5.4.2, page 136

[199] Westpower's Asset Management Plan 2014-2024 – section 5.4.2, page 137

[200] Infometrics, http://infometrics.co.nz/Forecasting/ForecastArticle.aspx?id=68

Figure 35: Global Dairy Trade Price Index
Fonterra – GDT



As at January 2015, ANZ Research, cut its 2014/15 milk price forecast again to $4.35kg MS, which ANZ notes is:

> "...well below break-even for many dairy farmers and represents an approximate $6.9bn (or 3.1% of GDP) hit to overall dairy revenue compared to last season."[201]

On 29 April 2015, Westland Milk Products cut its forecast payout for the current season to $4.90 - $5.10 per kg of milk solids, before retentions, compared with previous forecast of $5 to $5.40 a kg, reflecting lower international dairy prices.

As for the medium term outlook, ANZ explains:

> "A more modest recovery in dairy prices, combined with a strong NZD is weighing on the outlook...We are projecting milk powder prices to recover to around the US$2,800-$3,000 per tonne mark by the middle of the year and then US$3,300-US$3,500 per tonne by early 2016".

This forecast 'recovery' would bring the weighted average dairy price back to just below its seven average price of US$3,688, well down from the growth period when prices hit a high in February 2014 of US$5,042. In short, the forecast recovery is simply for a return to slightly below average prices.

In a more recent commentary[202], economics consulting firm, Infometrics, noted some down-side risks to Fonterra's farm-gate pay-out:

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[201] "NZ Dairy Update", ANZ Research, January 2015 - http://www.anz.co.nz/resources/3/c/3c283933-d208-4a19-b7a4-e94252d12fb4/ANZ-Dairy-Update_20150120.pdf?MOD=AJPERES

[202] Infometrics, http://infometrics.co.nz/Forecasting/ForecastArticle.aspx?id=68

"The sharp decline in dairy prices since their February peak will have a significant effect on farmers' incomes and their willingness to spend and invest this dairy season...After peaking in February, milk prices at Fonterra's GlobalDairyTrade forward auctions have declined close to 50%. Fonterra's current payout forecast for the 2014/15 dairy season is $5.30/kgms (down from $8.40/kgms last season), but there are downside risks to this payout. These risks stem from Fonterra's assumption that milk prices at GlobalDairyTrade auctions will recover 30% by March 2015."

Infometrics also set out some serious concerns about the medium term outlook for the dairy industry:

"A temporary hit to incomes will have little effect on spending as it can easily be smoothed out by drawing on short-term credit facilities. However, permanently lower dairy returns would cause a rethink of underlying operating practices and production capacity for some farmers. [Shading added for emphasis]

As with all markets, global dairy prices are the outcome of both supply and demand factors. Unfortunately for New Zealand, both of these factors are pushing in the "wrong" direction at present. Not only has global demand for traded dairy products shown some softness over recent months, but supply from other key dairy-producing nations is picking up strongly.

...we expect ongoing growth in demand for protein in emerging nations to continue pushing up global dairy demand over the medium-term.

However, supply-side driven weakness to global dairy prices is of greater concern. The key lifts in supply from other dairy-producing nations at present are coming from Europe and the US. Milk production in the European Union rose by 5.0% in the six months to June from a year earlier, while production in the US over the three months to August was up 3.0% from a year earlier.

To put the magnitude of these increases in perspective, a 5.0% lift in Europe's annual production is equivalent to around one-third of New Zealand's annual milk production, while a 3.0% boost in annual US milk production is equivalent to around 12% of New Zealand's total annual milk production.

Although the pace of this supply growth is likely to moderate over the coming year in response to sharply lower dairy prices, Northern Hemisphere dairy producers still pose a significant competitive threat over the medium-term, particularly when one factors in the upcoming abolition of milk quotas in Europe in April 2015. This policy shift will support both a permanent structural lift in the level of European milk production and a concentration of this production in the parts of Europe that produce milk most efficiently.

...

> After weighing up all of these factors, we assess that risks to Fonterra's farmgate milk price forecast of $5.30/kgms for the current dairy season are skewed to the downside. Although we expect a gradual lifting of demand-side constraints to support some stabilisation of dairy prices moving into 2015 and beyond, we anticipate that ongoing strength in global dairy supply will remain a limiting factor that prevents global dairy prices from returning to their lofty heights of the 2013/14 season anytime soon." [Shading added for emphasis]

Infometrics also highlights the exposure of regions that rely heavily on the diary industry. In the Westland region, it represents 21% of GDP. Only three other regions are above 20%. For New Zealand as a whole, it is 2% of GDP. Above 10% is highly exposed. Infometrics notes that in highly exposed districts:

> "the lower dairy payout will not only reduce farmers' incomes, but there will also be significantly slower growth in activity in other parts of these local economies. This flow on effect will be caused by dairy farmers and their contractors showing a reluctance to spend and invest on anything but the necessities." [Shading added for emphasis]

Given this outlook, Westland Milk Products and its suppliers are likely to be rather cautious about expanding capacity in the medium term. It is reasonable to conclude, therefore, that Westpower's forecast 8 to 13 MW of growth in electricity demand from the diary sector between 2013 and 2023 is likely to be premature.

10.4.3 Mining outlook

Westpower's other main source of expected growth in electricity demand in its 2014 Asset Management Plan forecast is Solid Energy establishing a new open-cast coal mine near Strongman, which could increase its electricity demand by about 4 MW in 2018.

Solid Energy contracted Geotech Limited in 2011 to run a trial (or case study) open-cast mine[203]. However, this also involves significant issues relating to the containment of the now closed underground mine at Strongman. As reported by Geotech Limited:

> "Work [on the open-cast mine project] has focused on post-mining rehabilitation and remediation. Underground stopping and fire fighting is undertaken with the task of creating "curtain walls" to contain fires with slurry pumping at pressure to fill voids. Coal winning is being conducted to support these activities"[204]

Apart from a range of major technical and feasibility issues, whether an open-pit mine is established at Strongman will depend heavily on future coal prices. On 27 February 2015, in advising that its half-year accounts will be delayed, acting chairman of Solid Energy, Andy Coupe, explained that:

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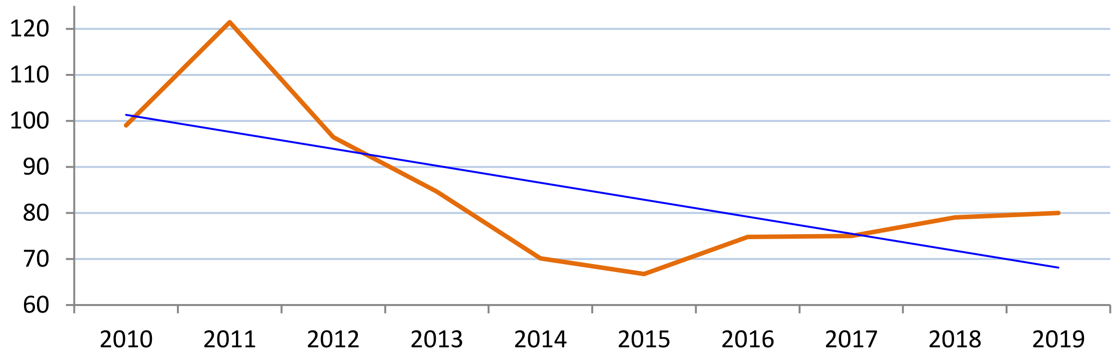
[203] http://www.geotech.net.nz/geotech-case-study-strongman-open-pit-coal-mining

[204] http://www.geotech.net.nz/geotech-projects-strongman

"...coal prices will remain lower for longer than has been predicted and that they will not recover as quickly...[The delay in our half year accounts] is about the impact on our balance sheet of future pricing for coal and our consequent diminishing ability to repay or refinance debt when it falls due from September 2016."[205]

Figure 36: Actual and expected international coal prices

Source: Economist Intelligence Unit: Coal (US$/tonne), February 2015



Given Solid Energy's challenging financial position, technical issues at Strongman, and the current medium term outlook for coal prices, it is reasonable to conclude that the prospects of establishing a commercial open-cast mine at Strongman during Westpower's forecast period has a low probability and therefore Westpower's forecast of an additional 4 MW of electricity demand in 2018 must be quite unlikely.[206]

10.4.4 Lack of caution in relation to step changes in demand

Since at least 2003, Westpower has consistently over-estimated electricity demand growth in its region. As shown in appendix 1 of this report, its forecasts have been, year after year, wildly over-optimistic. Westpower seems to have a particular focus on growth.[207] This despite Westpower acknowledging every year since at least 2003 that:

"...the West Coast has a history of premature major development announcements being made, only to fall through when macro-environmental changes occur such as the gold price dropping or a change in government policy. For this reason, the projected step load changes must be viewed circumspectly until there is a firm commitment."[208]

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[205] "Solid Energy half-year accounts deferred", media release by Solid Energy, 27/02/2015 –

http://www.solidenergy.co.nz/solid-energy-half-year-accounts-deferred/

[206] In section 5.7.4 of its Asset Management Plan for 2014 – 2024 at page 149, Westpower refers to several possible coal mining developments in the Rapahoe region and notes that: "Under the current economic circumstances, these projects are given a relatively low probability weighting". It is not clear if this is referring to the Strongman open-cast project.

[207] Westpower's Asset Management Plan 2014-2024, section 2.2.3, page 41, where it states: "AMPs [Asset Management Plans] must address growth". It would be more correct to say that AMPs should optimise assets (resources) over time to most efficiently meet demand. Under some scenarios, demand may decline (as has occurred on the West Coast), in which case assets need to be re-optimised to meet lower medium to long term demand.

[208] Westpower's Asset Management Plan 2014-2024, section 5.4.2, page 136, and previous Asset Management Plans since at least 2003. See also section 5.4.1.1 – "Similarly, overall economic activity on the West Coast has led to a cyclical "boom and bust" tradition throughout the history of power supply to the West Coast and this serves to highlight

From Westpower's forecasting track record, it would seem doubtful that Westpower has applied is stated policy of viewing step load changes circumspectly to the forecast in its Waitaha application.

10.4.5 Conclusion on Westpower's demand outlook

In conclusion, the case for the 15 year demand growth forecast in Westpower's Waitaha application appears to be very weak. It is not supported by the evidence. It is also inconsistent with three other forecasts: namely, Westpower's forecast in its 2014 Information Disclosure, Transpower's 2014 forecast for the West Coast, and MBIE's 2015 national demand forecast.

Further, based on current evidence of the medium term outlook, Westpower's forecast step change in peak demand from 48.5 MW in 2014 to 62.7 MW in 2023, with the main growth coming from dairying and mining, would appear to have a low probability of occurring.

10.5 Electricity supply available to Westpower's region

10.5.1 Overview

Westpower's network is supplied with electricity from two sources:

- Generation stations embedded within Westpower's network; and
- The transmission grid, which feeds electricity into several nodes (also called 'grid exit points').

The capacity of Westpower's substations also needs to be taken into account.

10.5.2 Supply from embedded generation

The generation stations embedded within Westpower's network are set out in the table below.

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the uncertainty that needs to be taken into account during the forecasting process. High commodity prices for resources such as gold and coal can lead to major step load increases, as seen over the last 10 years, but these loads can disappear equally quickly when the markets decline".

Table 9: Hydro stations embedded in Westpower's network:
Source: Electricity Authority and Westpower[209]

West Coast embedded hydro stations	Owner	Capacity (MW)	Date built	Annual output (GWh)
Arnold	Trustpower	3.1	1932/1992	20.0
Dillmans	Trustpower	3.5	1928/1978	16.0
Duffers	Trustpower	0.5	1928/1979	2.0
Kumara	Trustpower	6.5	1928/1978	30.0
Fox	Trustpower	0.2	1933	1.9
Kaniere Forks	Trustpower	0.4	1909	4.0
McKays Creek	Trustpower	1.1	1931	8.0
Amethyst	Westpower	7.2	2013	30.0
Wahapo/Ōkārito Forks	TrustPower	3.1	1960/1991	15.3
Turnbull	NZ Energy	1.0	1974	
Total		**26.6**		**127.4**

Dillmans, Duffers and Kumara are operated as an integrated scheme by Trustpower. They share the same water and are offered into the market as a single 10 MW generator.[210] It seems to have some capacity to manage the timing of when it uses inflows.

Transpower's 2014 Annual Planning Report (at section 16.4) forecasts West Coast annual generation capacity to 2029 to continue at current levels – namely, 26MW.

10.5.3 Supply from transmission grid

As noted earlier, transmission capacity into the West Coast (including Buller) is:

[209] Distilled from Electricity Authority's list of power stations – https://www.ea.govt.nz/dmsdocument/8621. For some reason, McKays Creek and Kaniere Forks stations are not mentioned as embedded hydro sources in Westpower's Asset Management Plan 2014-2024 – see Figure 3.17 at page 106

[210] Transpower's 2014 Annual Planning Report, at section 16.4

Into West Coast	60 MW
Out of West Coast	100 MW

Source: Transpower

As noted earlier, the 2011 upgrade in transmission was provided to meet extremely aggressive demand forecasts in 2007/08. Westpower acknowledges this in its 2014 Asset Management Plan[211]:

> "Currently, there is sufficient n-1 transmission capacity available in the transmission network feeding the West Coast, to ensure that major new loads can be supplied on an uninterruptible basis, and so **electricity supply should not be a constraint** to future economic development." [Emphasis added]
>
> "The DOB-TEE A line effectively doubles the transmission capacity, **thus providing security to the West Coast.**" [Emphasis added]

Further, the transmission capacity referred to above is not the thermal capacity of the transmission lines but rather the transfer limits, which are governed by voltage factors. In the unlikely event that demand was to grow beyond the current transmission capacity in the reasonably foreseeable future, more capacity can be accessed by installing additional capacitor banks.

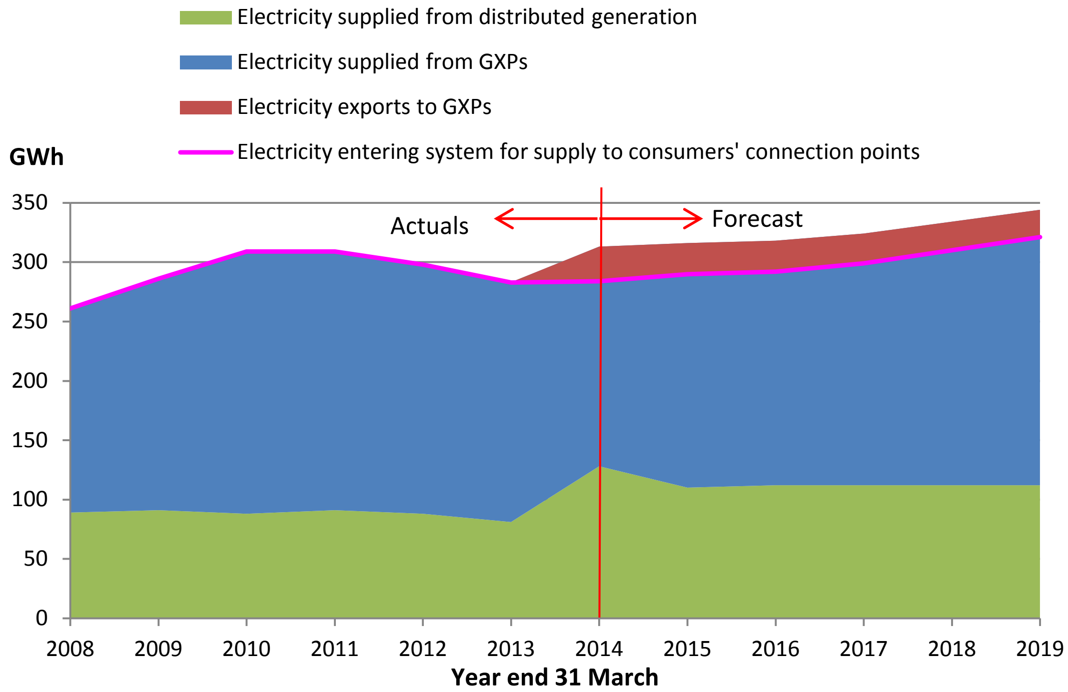
The 2011 transmission upgrade resulted in a significant improvement in reliability and security of supply, which is outlined in a later section of this report.

10.5.4 Mix of supply from transmission and embedded generation

The historical and forecast mix of supply from transmission and embedded generation is shown in the chart below.

[211] Westpower's Asset Management Plan 2014-2024, section 5.4.2, pages 136 and 137

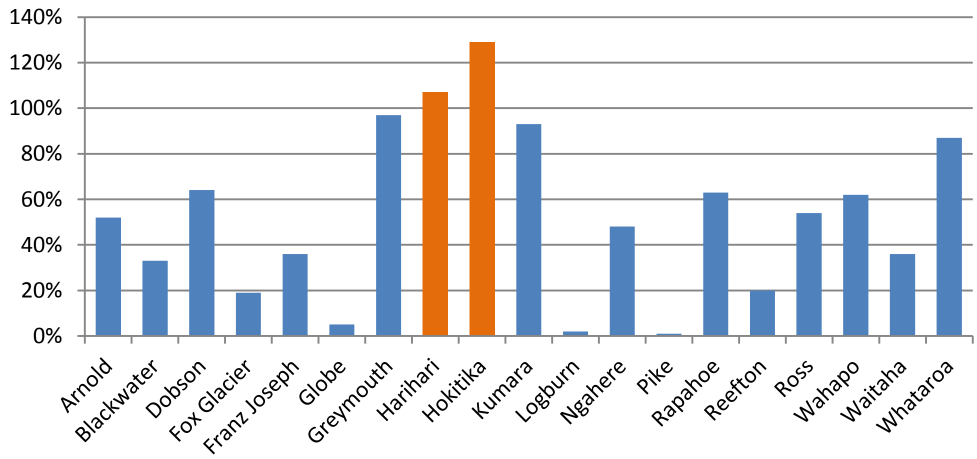
Figure 37: How peak demand is supplied on Westpower's network.
Source: Westpower's Information Disclosure to Commerce Commission



10.5.5 Capacity of Westpower's substations

Westpower's 2014 Information Disclosure indicates that it considers the capacity of its existing substations to have adequate capacity to accommodate its demand growth forecasts. Westpower did not forecast any increased in installed capacity (MVA) over the next five years. Westpower's forecast utilisation of installed capacity of each substation in 2019 is set out in the chart below.

Figure 38: Substations on Westpower's network – forecast utilisation of capacity in 2019.
Source: Westpower's 2014 Information Disclosure to the Commerce Commission



Westpower reported that no constraints are forecast at any substations within the next five years, except for transformers at Harihari and Hokitika. In relation to the:

- Harihari substation, Westpower considers that the base load growth has been decreased to 1.0% to reflect a steady peak load and as result the transformer should **not** require replacement within the next 10 years.

- Hokitika substation, the increased utilisation assumes that Westland Milk Products will make a step increase in its electricity consumption. However, Westpower notes that the constraint mainly applies during maintenance periods and the issue could be resolved at the maintenance planning stage and/or by implementing a load management programme.[212]

10.5.5 Capacity of Westpower's sub-networks

The key points in relation to capacity adequacy at Westpower's sub-networks are as follows:[213]

Table 10: Adequacy of Westpower's network capacity
Source: Westpower's 2014 Asset Management Plan

Sub-network	Adequacy of existing capacity to 2024
Reefton	No significant load growth is contained in the loadwatch analysis for the Reefton area. The existing network should be adequate to handle on-going growth.
Greymouth	Closure of Pike River coal mine reduced demand by 6 MW. Closure of Spring Creek Mine further reduced demand by 5 MW. Muted base load growth and continuing expansion in the tourism industries will require minor capacity increases in the long term, but probably outside the planning horizon**.** The existing Westpower network can support expected load growth. The recent upgrading of the main transmission line has also strengthened the supply, significantly improving firm capacity into the area. If and when the Trustpower proceeds with its proposed 40 MW Arnold power station, a new substation may be required at Kokiri to connect the power station into the local transmission grid. The new substation may be required by 2018/19, depending on a final decision to proceed from Trustpower.
Hokitika	Capacity was upgraded in 2002 to meet demand from Westland dairy factory. The factory is likely to continue with plans for step load increases throughout the planning period, and this will require some reconfiguration and possible augmentation of the cables into the plant, along with changes to the network within the plant itself. No other major network development is planned in this area for the remainder of the planning period.

[212] Westpower's Asset Management Plan 2014-2024, section 5.4.4, page 140

[213] Westpower's Asset Management Plan 2014-2024, section 5.7, page 147 – 149

South Westland	Major step load increases are conceivable in the Franz Josef area if tourism industry decides to invest heavily in new accommodation units. Mitigating this driver, however, is an increase in concern around the proximity of Franz Josef and Fox glaciers to the major Alpine Fault and the creation of a Fault Avoidance Zone by the Westland District Council that prevents development in some areas of these townships. If Waitaha hydro project proceeds, Hokitika-Harihari line may be upgraded in 2018 or later, and this may require further work or reconfiguration at Ross and Waitaha substations.

[Shading above has been added in the table above for emphasis]

10.6 Conclusion on adequacy of supply capacity relative to demand

Drawing the above information together, the supply and demand situation on Westpower's network can be summarised as follows:

Current electricity supply capacity via transmission grid	50 MW
Plus current supply capacity of generation embedded	26 MW
Total current supply capacity	**86 MW**
Less current peak electricity demand (as at 31 March 2014)	48 MW
Current surplus peak capacity	**38 MW**

Applying the growth rate in Westpower's 2014 Information Disclosure, it would take **38 years** to use up this surplus. It would take longer using Transpower's 2014 forecast, and even longer using MBIE's national growth forecast.

Even applying Westpower's aggressive growth forecast in its Waitaha application, the existing surplus capacity would not be used up until around 2034 (**20 years** from now).

Further, as outlined above, Westpower reports that there are no constraints in its network or substations that would limit demand growth.

It is therefore clear that no additional generation capacity is required to meet expected demand growth on Westpower's network.

In its 2014 Asset Management Plan, Westpower acknowledges the 2011 transmission upgrade delivered security of supply:

> "Currently, there is sufficient n-1 transmission capacity available in the transmission network feeding the West Coast, to ensure that major new loads can be supplied on an uninterruptible basis, and so **electricity supply should not be a constraint** to future economic development." [Emphasis added]

Well into the future, at a time when existing supply capacity feeding Westpower's network is becoming insufficient to meet demand, additional capacity can be provided at a relatively low cost by upgrading capacitor banks and the like at grid exit points to enable greater capacity to be delivered on the Dobson transmission lines.

11. Economics of the Waitaha scheme

11.1 Outline of this section

This section 11 is divided into the following parts:

- Summary of key points
- Test of financial viability
- Methodology
- Expected wholesale prices for Waitaha output
- Generation-weighted prices
- Unit cost of Waitaha power
- Financial viability of Waitaha scheme
- Other related matters

Several of the headings above have sub-sections.

11.2 Summary of key points

The key points in this section 11 are as follows:

- The analysis indicates that Waitaha inflows and 'take' volumes follow a very similar seasonal pattern to the Waitaki scheme, and that they do not capture the full price at Westpower's off-take node.

- Comparing annual average prices indicates that the Waitaha scheme's annual average generation-weighted price would be reasonably close to projections of the annual average wholesale prices at the Benmore node outlined in section 8.5 of this report. This sets a more demanding ceiling on the proposed scheme's unit cost than the unweighted wholesale price at Westpower's key off-take nodes.

- In the absence detailed project data, a reasonable desk-top proxy for estimating the unit cost of the Waitaha scheme is to derive and compare it on a like-for-like basis with the hydro generation options in MBIE's 2015 LRMC rankings, which are set out in sections 9.7 of this report.

- Applying a range of possible capital costs and annual energy output, Waitaha scheme's estimated unit cost ranges from **$94.78**/MWh to **$109.90**/MWh on a like-for-like basis with projects ranked in MBIE's model.

- Based on the price paths and analysis set out below, it is unlikely that the proposed scheme would be financially viable in the reasonably foreseeable future.

11.3 Test of financial viability

As set out in section 5 of this report: "Firms should only invest in additional generation plant when the wholesale electricity price and frequency of supply scarcity generates sufficient operating surplus to justify new generation plant."[214]

The question in this case is, therefore, whether relevant wholesale electricity prices and frequency of scarcity would generate sufficient operating surplus to justify the Waitaha scheme. If not, it is not financially viable.

For a new generation scheme to be embedded in the local distribution network, the assessment needs to take into account the benefit of any reduction in transmission costs (caused by the proposed new generation) for electricity still purchased from the grid.

11.4 Methodology

11.4.1 Overview

As noted in section 5 of this report, when it is not possible to carry out a detailed discounted cashflow (DCF) analysis, the orthodox methodology for assessing whether a new generation project is likely to be financially viable is to measure whether wholesale prices likely to be received over the medium to longer term for electricity sold from the proposed scheme are, on average, above or below the full cost of producing it – if below, the proposed scheme is negative in net present value terms, which means it is neither an efficient choice of new generation nor financially viable.

The two primary factors are future wholesale electricity prices and the full cost of supplying electricity from the proposed scheme, both over the medium to long term. Two key elements in relation to the cost of electricity from a new hydro scheme are the total capital cost and the cost of capital. These factors are discussed further below.

"Frequency of supply scarcity" is mentioned in the test of financial viability set out under the previous heading. In the methodology to be applied in this report, the degree and frequency of "scarcity" of electricity supply is reflected in the medium to longer term pattern of wholesale prices.

[214] Test for investment in new generation set out in "A Critique of Wolak's Evaluation of the NZ Electricity Market: Introduction and Overview" by Prof Lewis Evans, Seamus Hogan and Peter Jackson, Working Paper No. 08/2011 at pages 9-10

11.4.2 Expected wholesale prices for Waitaha output

Expected wholesale prices over the medium to longer term for New Zealand are outlined in section 8.5 of this report. This price path can be compared to the likely cost of supplying electricity from the proposed Waitaha scheme to give a general indication of whether the scheme is likely to be financially viable.

However, this can be made more granular – that is, more specific to the Westpower's context – by adjusting the expected price path to reflect transmission 'location factors' – that is losses and any constraints – in delivering electricity to Westpower's network. (These are explained in section 3 of this report). Wholesale prices are then established at Westpower's grid exit points, which would be the price reference points for electricity supplied by the proposed Waitaha scheme.

The next level of granularity is to adjust the prices at Westpower's grid exit points to reflect the volumes of water that the Waitaha scheme is likely to have available each day for electricity production and match it with the prices at Westpower's grid exit points when those volumes of water used. This gives a 'generation-weighted' price.

Using actual water inflow sequences in the Waitaha catchment and applying the proposed operating parameters,[215] it is possible to estimate the volumes of water that would be available for hydro generation in the Waitaha scheme. These water 'take' volumes can then be used to estimate electricity production from the proposed scheme. Each daily volume of generation can then be matched to the actual wholesale electricity prices at Westpower's grid exit points on the dates of the actual water inflows. This gives a 'generation weighted' wholesale price, which can then be compared to the estimated long run cost (or unit cost) of electricity from the scheme. A comparison of the generation-weighted price to the estimated unit cost provides a strong indication of whether the scheme is likely to be financially viable.

11.4.3 Unit cost estimate for Waitaha scheme

The key components of the unit cost for an electricity generation scheme are its variable operating and maintenance costs (**VOM**), fixed operating and maintenance cost (**FOM**) and capital costs, all expressed relative to electricity output:

Unit Cost ($/MWh) = **FOM** ($/MWh) + **VOM** ($/MWh) + **Capital charge** ($/MWh)

For hydro generation, operating and maintenance costs are comparatively low. In MBIE's model, estimated FOM and VOM (combined) amount to approximately 2% to 2.7% of unit costs for the top eight new hydro generation options as ranked by lowest project LRMCs in MBIE's model.

The main component in the unit cost of any new hydro scheme is the capital charge. In essence, this is the total capital cost amortised over an economic period using an appropriate discount rate.

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[215] Sourced from the hydrology data in Westpower's Waitaha application

The total capital cost includes the direct costs of all plant, materials, equipment and buildings, all labour costs associated with construction, installation and commissioning, as well as owner's costs such as land, development approvals, legal fees, inventories, and the like. The total cost should also include the costs of connection to the network.

Amortising the total capital cost into a capital charge is mainly a function of duration and discount rate; that is to say, the choice of discount rate and period can have a material impact on the level of the annual capital charge. These variables are discussed further below in relation to the Waitaha scheme.

11.5 Expected wholesale prices for Waitaha output

11.5.1 Overview

As outlined above, estimating the expected wholesale prices for electricity produced by the Waitaha scheme has three reference points:

- Projected national wholesale electricity prices over the medium to longer term;
- The impact of 'location factors' – that is, the difference between prices at the relevant grid injection point and the grid exit point. (Location factors for Westpower's grid exit points are set out in section 3 of this report); and
- The generation-weighted price that Waitaha power is likely to receive – that is, the price at the grid-exit point received for particular volumes of output.

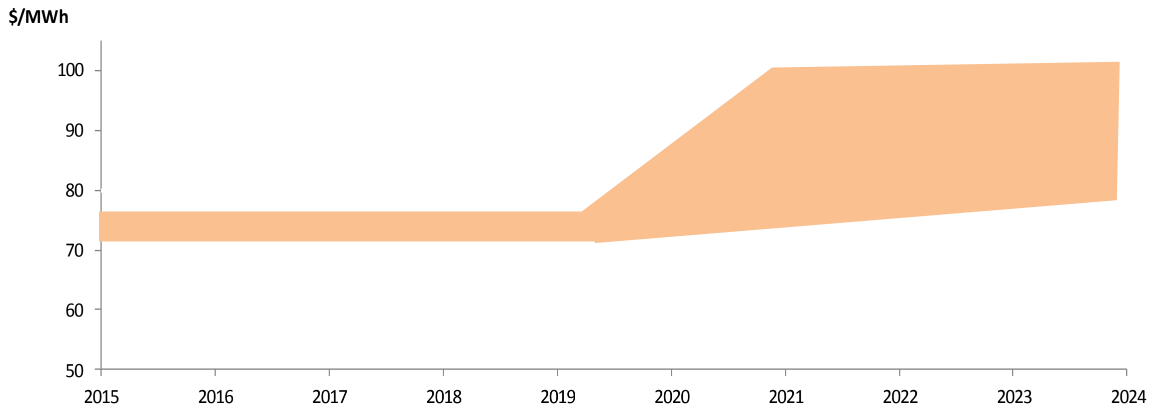
11.5.2 National wholesale price

As outlined in section 8.5 of this report, current projections of wholesale electricity prices over the medium to longer term for New Zealand are as follows:

- Until the end of 2019, average wholesale electricity prices are likely to stay at around $73 to $75/MWh
- Beyond 2019, it is not clear:
  - MBIE's draft base case assumes a rise to $102/MWh in 2021.
  - If there is high geothermal availability, MBIE projects a lower more gradual price path with prices not reaching $100/MWh until 2027.
  - Market analysts are projecting a gradual rise from around $75/MWh in 2019 to $80/MWh later in 2025, assuming Tiwai stays open at 400 MW. (If Tiwai continues at 572 MW, the price might lift about $5/MWh).

The range of these projections is shown in the chart below. (It is important to keep in mind that MBIE's assumption is an input into Transpower's capital expenditure parameters, which is a different context to that of market analysts' projections).

Figure 39: Current view of future average wholesale electricity prices
Source: Author, MBIE, FNZC



- The future of Tiwai is a material factor that could change the price outlook significantly. Its closure would have a lowering effect on prices and defer new generation.

- As noted in section 5 of this report:

  > "...in any market faced with the need to build new capacity (as a consequence of increased demand and the need to replace obsolete capacity) average prices would be expected to track the cost of building new capacity. This is both because such prices provide the incentive needed to build new capacity and because, in a competitive market, all prices trend to the same level"[216]

- The current outlook for wholesale electricity prices indicates that there is no need to build new capacity.

11.5.3 Location factors

Any estimate of future wholesale prices for New Zealand as a whole need to be adjusted for losses and grid constraints in transporting electricity to Westpower's grid exit points. Losses and constraints are expressed as a 'location factor', which reflects the price difference between a reference point and the relevant grid exit point.

[216] "Ministerial Review of Electricity Market Performance", Electricity Technical Advisory Group and the Ministry of Economic Development, August 2009, Volume 2, at 239

As outlined in section 3.10, wholesale prices at Westpower's grid exit points (also called off-take nodes) are around 8.5% to 13% higher on average than at the Benmore reference node.[217] At face value, it might therefore be assumed that the price path outlined above might be 8.5% to 13% higher at Westpower's main off-take nodes.

However, as outlined below in section 11.6 above, when prices at Westpower's main nodes are adjusted to reflect the Waitaha scheme's expected pattern of generation based on water flows, the higher prices due to transmission losses are cancelled out.

11.5.4 Generation-weighted prices

It is possible to derive actual average daily water inflow data for the period 25 March 2006 to 18 April 2012 from data provided by Westpower to Whitewater NZ. This can be matched against actual average daily wholesale electricity prices at Westpower's grid exit points (also called off-take nodes).

The analytical steps followed in relation to a generation-weighted price for the Waitaha output include the following:

- First, determine a representative grid exit point (so that it is not necessary to calculate generation-weighted prices for all Westpower's grid exit points);
- Second, establish the expected daily volumes of water that the Waitaha scheme is likely to receive for generation given the operating parameters proposed;
- Third, compare the sequence of those 'take' volumes to the pattern of inflows to main existing generation stations in the South Island (the Waitaki scheme, for example);
- Fourth, convert the daily 'take' volumes into estimated output from the Waitaha scheme (in other words, convert cumecs of water into GWh of electricity produced);
- Fifth, match the 'take' volumes and estimated electricity output to actual average daily prices at the representative grid exit point;
- Sixth (from the previous step) establish the generation-weighted price that is likely to be received for electricity produced by the proposed Waitaha scheme.

These steps are applied below.

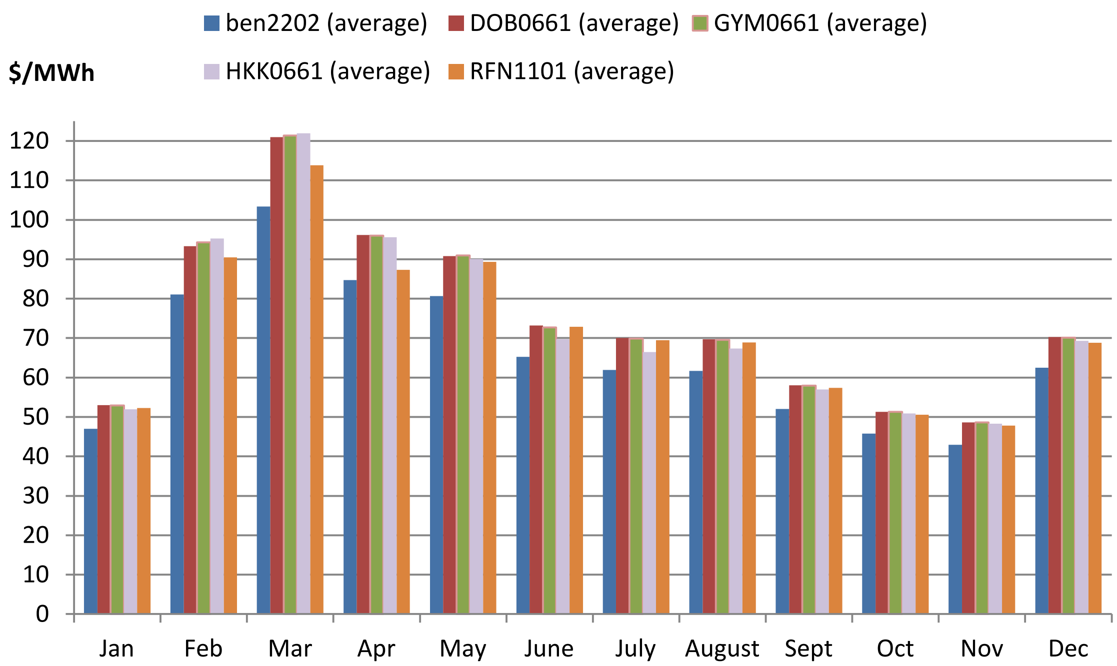
[217] Assuming that none of the price difference is due to constraints. The Benmore node is the location on the national grid at which Benmore power station injects electricity. Benmore is the southern end of the HVDC link, and if there are no significant intra-island constraints then half-hourly prices at the Benmore node generally reflect the half-hourly prices across the South Island. Benmore is one of the three key reference nodes, along with Haywards and Otahuhu. Source: 2009 Ministerial Review, Volume 2, Appendix 1

11.6 Generation-weighted prices

11.6.1 Representative node

The pattern of prices at Westpower's main grid exit points relative to each other and Benmore is shown in the chart below. (In the chart below, the grid exit points are: 'ben2202' - Benmore; 'DOB0661' – Dobson; 'GYM0661' – Greymouth; 'HKK0611' – Hokitika; and 'RFN1101' – Reefton).

Figure 40: Average monthly nodal prices – 2010 -2014
Source – Electricity Authority



Dobson, Greymouth and Hokitika are highest and there is not much difference in price level between them. So rather than run multiple prices, Hokitika (HKK0661) has been used to calculate the generation-weighted price.

11.6.2 Daily water 'take' for the Waitaha scheme

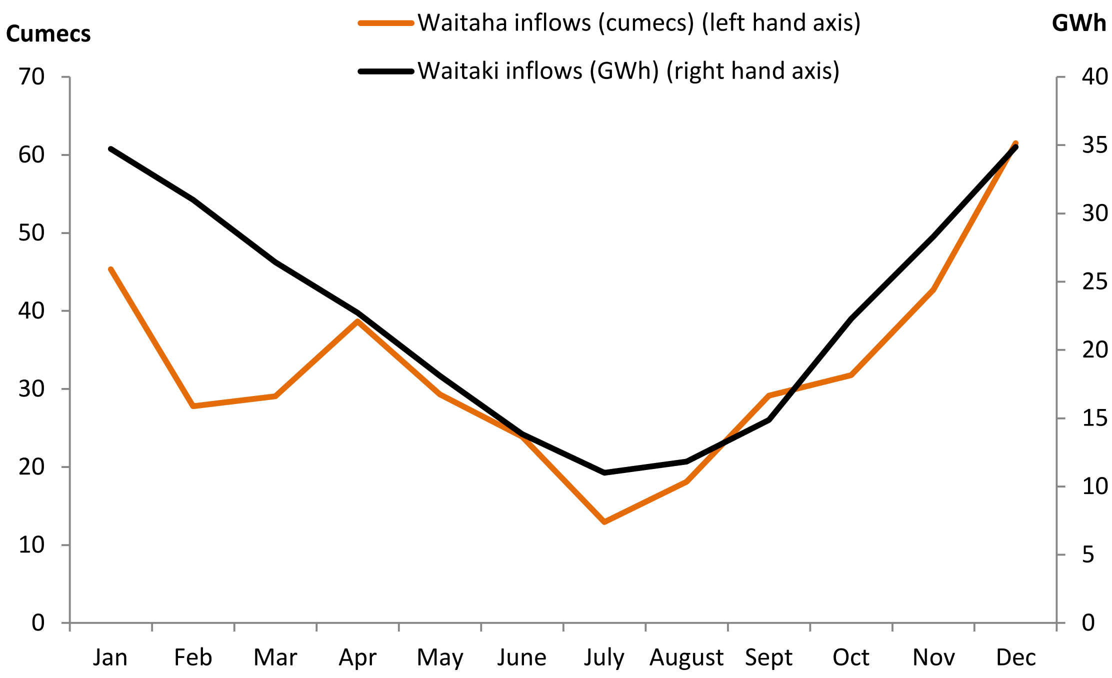
Actual average daily water inflow data has been provided by Westpower to Whitewater NZ for the period 25 March 2006 to 18 April 2012. Applying the proposed operating parameters, the actual water available for generation (the 'take') can be calculated. The key parameters are a requirement to leave 3.5 cumecs in the river, and to take no more than 23 cumecs.

11.6.3 Compare 'take' with Waitaki inflows

A key factor in assessing the value of any new generation proposal is to gauge the degree to which is it would be 'anti-seasonal' or 'counter-cyclical' relative to other hydro generation schemes. That is to say, would it produce higher volumes when other hydros are low on water?

Based on the 2006 to 2012 hydrology, the Waitaha is not 'anti-seasonal'. As shown in the charts below, its inflow and 'take' sequences closely parallel the Waitaki scheme.

Figure 41: Waitaha monthly inflows compared to Waitaki monthly inflows
Source: Westpower and Electricity Authority.
For Waitaki, 79 years of data to mid 2010. For Waitahi, six years of data from 2006 to 20012



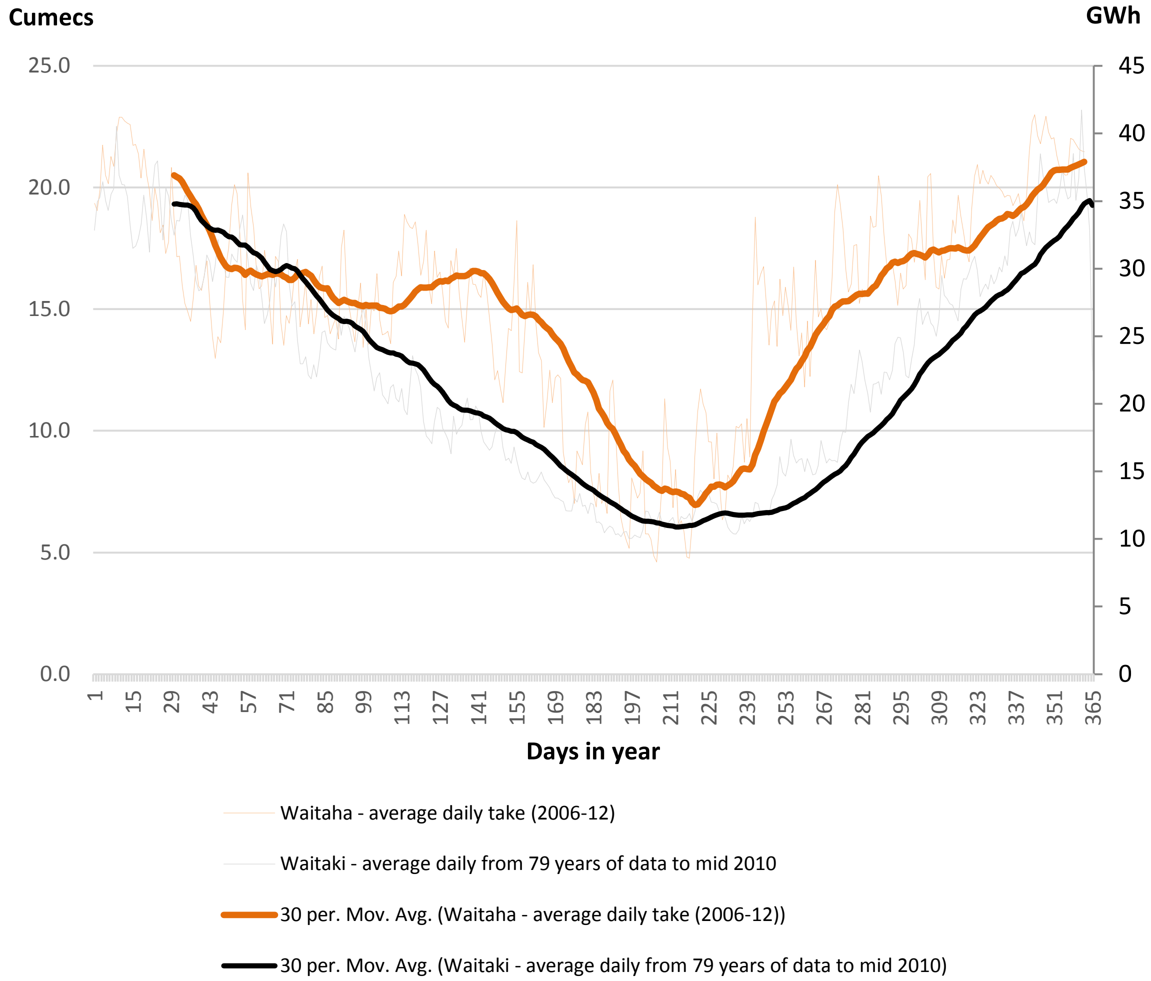
This is at odds with Westpower's claim in its Waitaha application that:

> "Also in relation to security of supply, the Scheme will provide geographic diversity of supply of electricity from hydro generating stations, which in the South Island are heavily dependent upon water catchments and climatic conditions in South Canterbury and Otago."[218]

[218] Westpower's Waitaha application at page 120

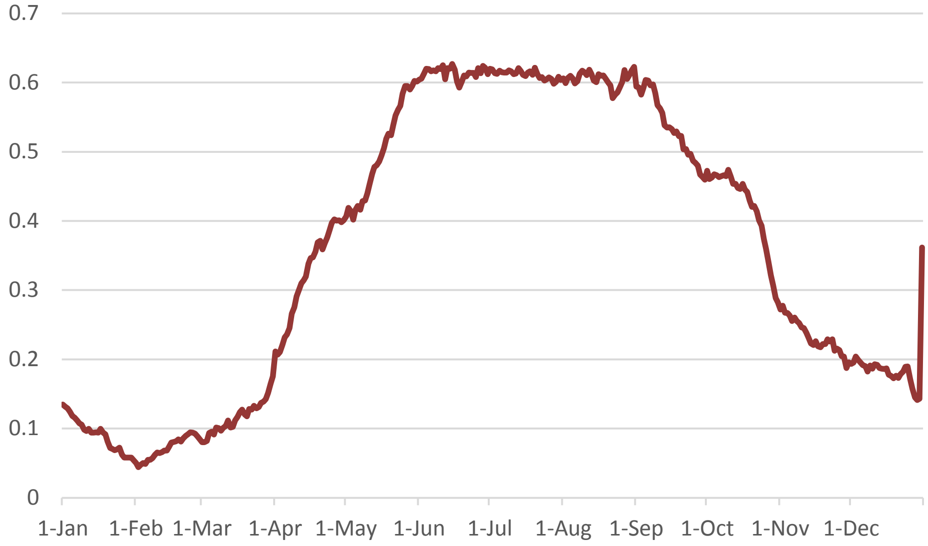
Figure 42: Waitaha daily 'take' compared to Waitaki daily inflows

Source: Westpower and Electricity Authority. Waitaki is right hand axis. Waitahi is left hand axis. 30 day moving average is shown with solid lines



By contrast, other South Island generation schemes are more 'anti-seasonal' – that is to say, they have high inflows in periods when the Waitaki has low inflows. For example, Highbank in Canterbury receives its main inflows during the winter period when the Waitaki has its lowest inflows.

Figure 43: Highbank power scheme – inflows
Source: Electricity Authority



Inflows into the Cobb power scheme in the Golden Bay area are reasonable steady year-round, but they also increase on average between May and October when Waitaki inflows are low on average,

11.6.4 Convert 'take' volumes to generation output (GWh)

As Parsons Brinckerhoff note in their 2011/12 report to MBIE, the net output factor (NOF) is project specific as it depends on many factors, such as; the availability factor, water storage capacity, local precipitation rates, inflows into the hydro scheme and the operational strategy of the generator.[219]

Standard industry formulae convert water volumes into generation output (GWh). The main variables are as follows. The assumptions can be varied as required. The numbers shown are indicative parameters for the purposes of estimating output from the proposed Waitaha scheme. These are of course subject to sensitivity analysis:

Efficiency	75-85%
Gravity	9.81
Water density	1000
Conversion factor J to GWh	2.78E-13
M-head	100
Loss Factor (%)	30

[219] "2011 NZ Generation Data Update", January 2012, Parsons Brinckerhoff, at section 4.2.8, page 141

The capacity factor of a generation scheme will vary with 'take' volumes. Given the hydrology outlined above, it is to be expected that the capacity factor of the Waitaha scheme would be lower during the winter months when 'take' volumes are lower.

As calculated by Transpower (in its capacity as 'System Operator'), the capacity factor for run-of-river hydro during winter 2010 to 2013 was 50% for 75% of the time. (By contrast, the capacity factor for geothermal generation was 90% for 75% of the time).[220]

11.6.5 Pattern of actual prices at Westpower's grid exit point

Before applying actual average daily prices to the actual daily 'take' volumes in the Waitaha river, it is helpful to review the pattern of wholesale prices at Westpower's Hokitika grid exit point in the relevant period, which is 2006 to 2012. (The period is set by the span of hydrology data provided by Westpower to Whitewater NZ)

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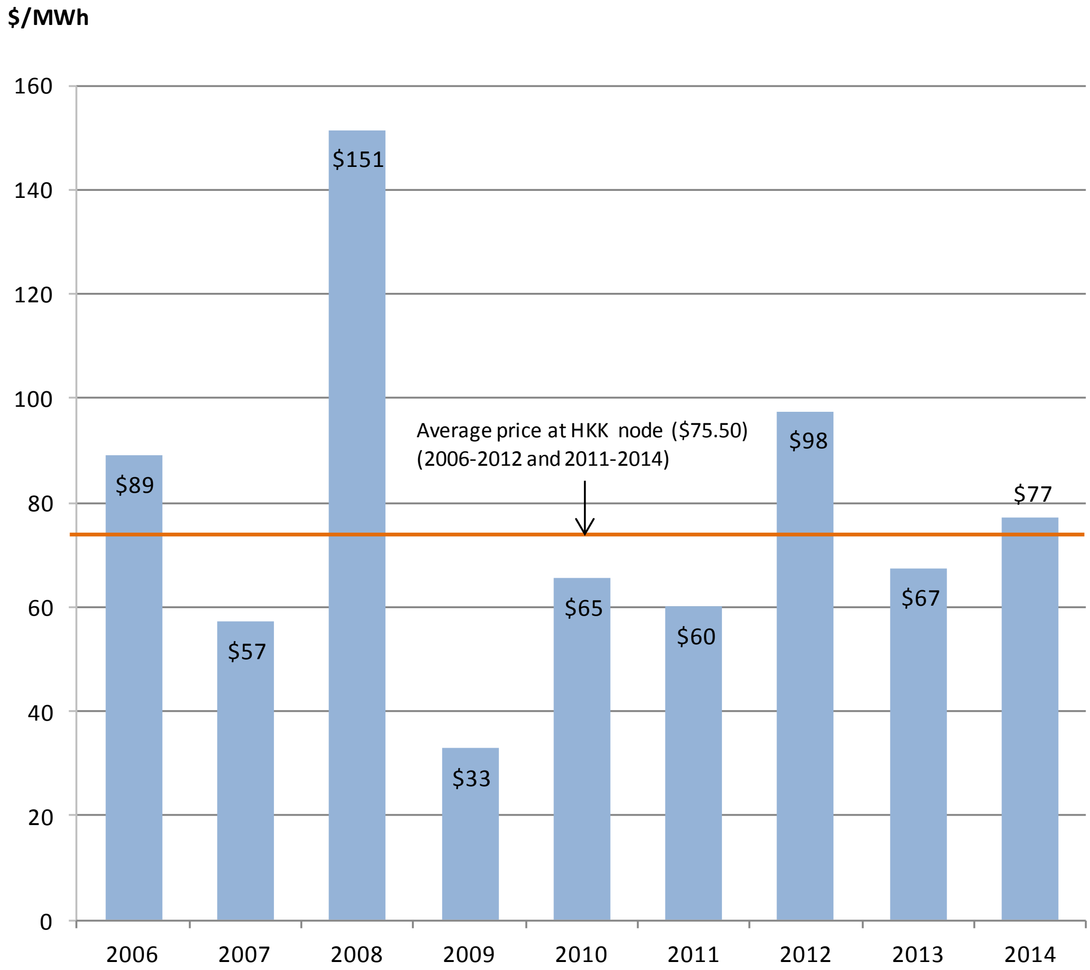
[220] "Security and Reliability Council: The system operator's annual assessment of security of supply", 28 May 2014, Transpower, page 37, Figure 32

Figure 44: Average daily wholesale electricity price at HKK0661.
Source: Electricity Authority data



Note that 2008 was a particularly 'dry year' – that is to say, inflows into the main generation catchments were very low, which resulted in relatively high average spot prices. By contrast, 2009 spot prices were on average significantly lower than in 2008 as catchment areas received above-average rainfall in the first nine months of the year. This gives data-set a reasonable representation of actual highs and lows.

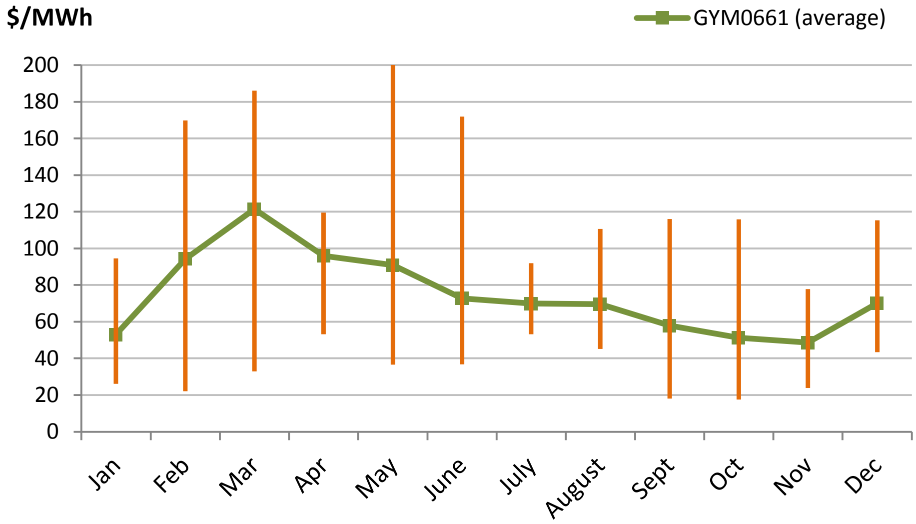
The average price at the Hokitika node for 2006 to 2012 (the period of the hydrology data-set) was $75.50/MWh, and for the last four years (2011 to 2012) it was $75.40/MWh

A key question is whether the Waitaha scheme would capture those high prices in 2008, and how much it would be affected by the low prices in 2009? This is examined below.

Note also that the 2014 price is reasonably close to the average national wholesale in 2014 ($78.28) and the price forecast by MBIE and market analysts for 2015 until at least 2019 and possibly longer ($75 - $73/MWh). (Further details on historical national wholesale prices are set out in section 7.6 of this report).

The range of prices within each month from 2010 to 2014 is shown in the chart below, together with the monthly average price during that period.

Figure 45: Range of unweighted monthly average prices at GYM0661 – 2010 to 2014.
Source: Derived from Electricity Authority data. Shows highest to lowest prices and monthly average spot price unweighted by demand or generation



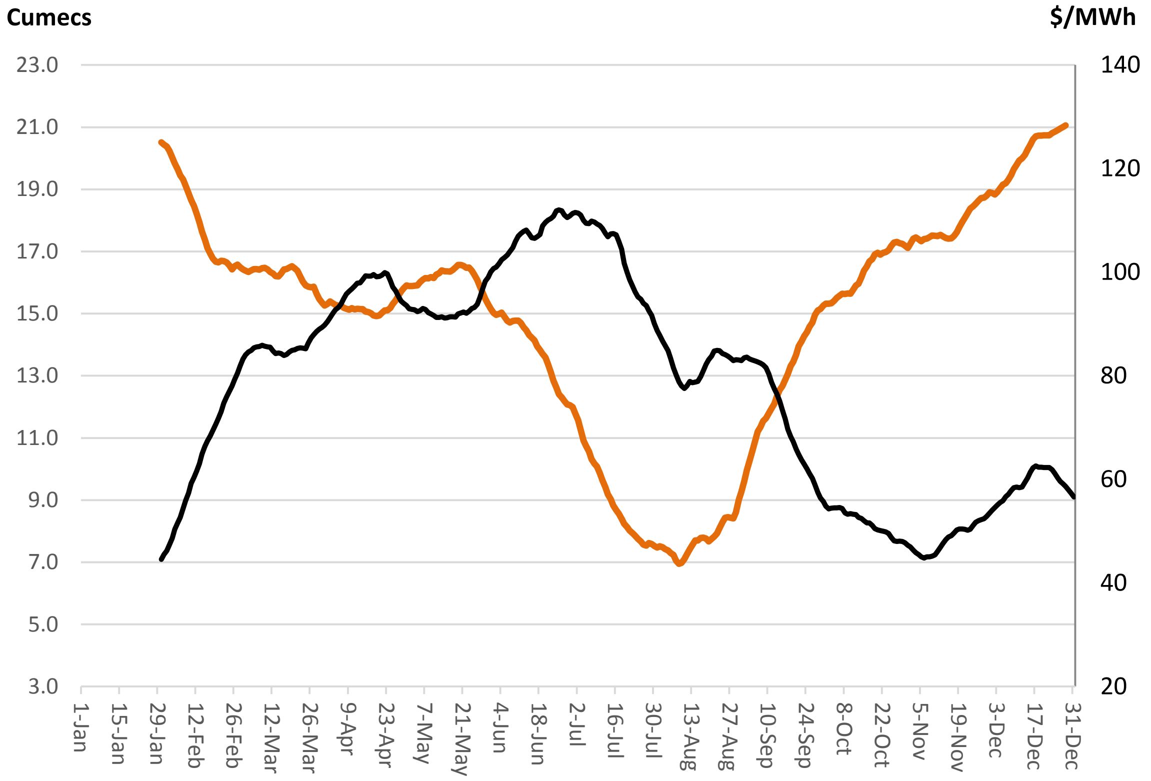
As explained in section 5.12, in the short term wholesale market prices are driven mainly by short term variations in generation capacity, transmission outages and constraints, changes in demand (often due to climatic temperatures), and changes in hydrological conditions (water inflows and water storage in the hydro catchments).

11.6.6 Do Waitaha 'take' flows occur when prices are high?

In short, the answer is no. Matching the average daily 'take' flows for 2006 to 2012 that would be used for generation in the Waitaha scheme against average daily prices for the same period at Westpower's Hokitika grid exit point (HKK0661) shows that the Waitaha scheme's generation would be negatively correlated with wholesale prices – that is to say, when 'take' volumes for generation are high, prices tend to be low; and when 'take' volumes are low, prices tend to be high. As shown in Figure 47, there is a reasonable match between February and May on average.

The charts below show average daily 'take' volumes for generation against daily prices at the Hokitika node for 2006 to 2012 (being the period of hydrology data provided by Westpower).

Figure 46: Waitaha generation relative to wholesale prices – 2006 to 2012
Source: Author using Electricity Authority and Westpower data – 25/3/06 to 18/4/12.
Explanation: The black line is the 30 day moving average of prices at HKK0661 (use right hand axis). The orange line is the 30 day moving average of 'take' volumes for generation (use left hand axis)



Rather than showing a 30 day rolling average, the chart below plots daily 'takes' against average daily prices at the Hokitika node. The lighter black sections show the 'mis-match' of where prices are high but 'takes' are low (late May to early September).

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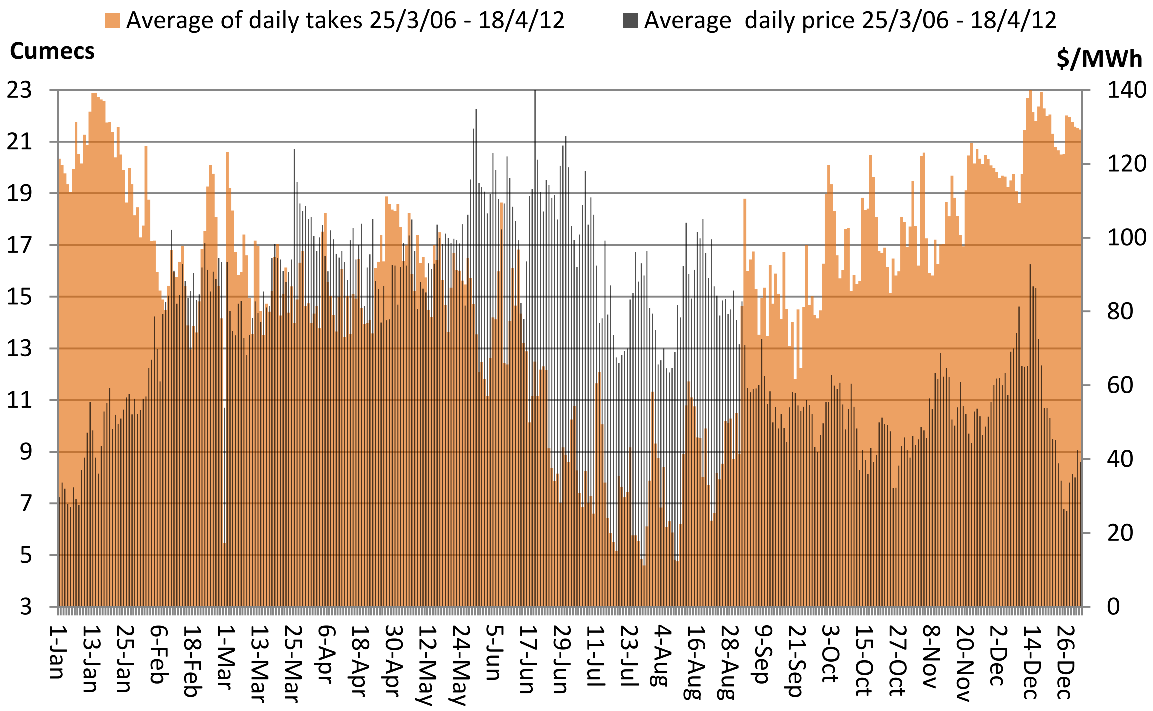
Figure 47: Waitaha generation relative to wholesale prices – 2006 to 2012

Source: Author using Electricity Authority and Westpower data – 25/3/06 to 18/4/12.

Explanation: Black is the average daily price at HKK0661 (use right hand axis). The orange line average daily 'take' volume for generation (use left hand axis)



As shown below, the negative correlation is worse in several individual years.

11.6.7 Generation-weighted prices

It is important to note that the proposed Waitaha scheme would not set or control the wholesale price received for any power it would produce. It is far too small to influence national spot prices, and as a run-of-river scheme it could not influence the timing of when it uses water to generate relative to the pattern of wholesale prices.

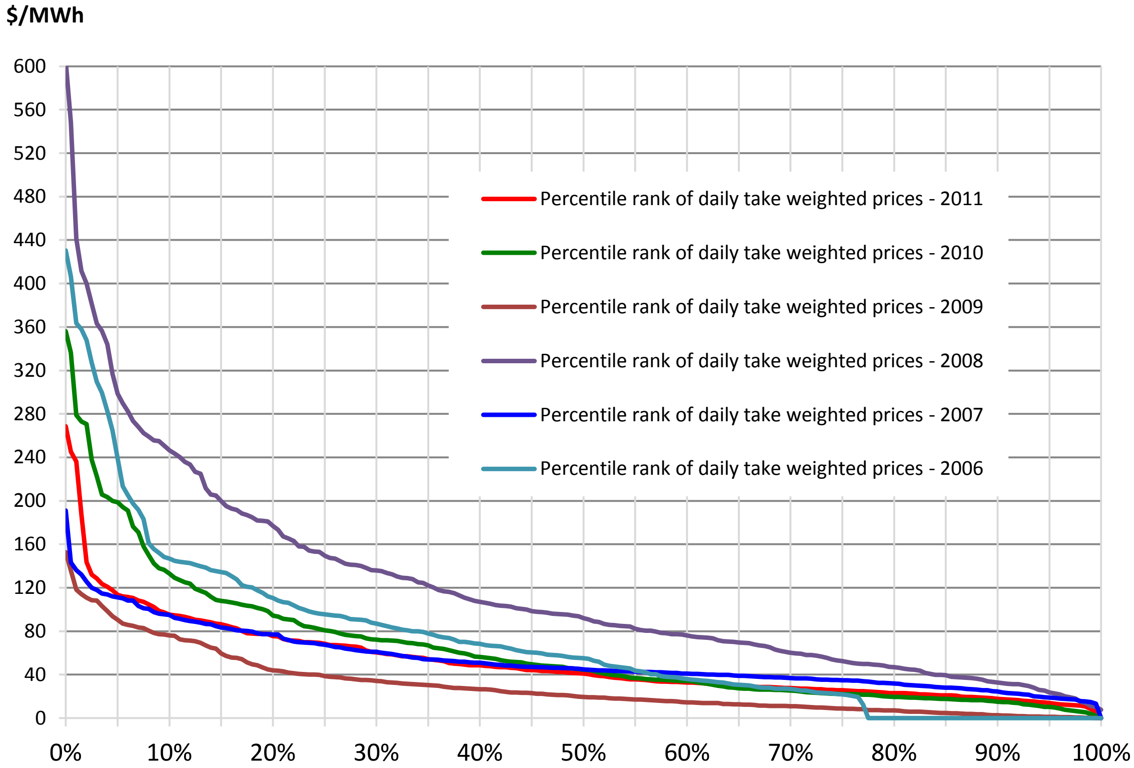
Using actual 'take' volumes based on actual daily inflows in the Waitaha River matched against corresponding actual daily prices at Westpower's Hokitika node produces generation-weighted prices for the Waitaha scheme. (Using 'take' volumes avoids any issues as to which assumptions to use in converting water 'take' into energy output). As noted above, the 2006 to 2012 data-set includes a very 'dry' year and a relatively 'wet' year, so it is reasonably representative. Note also that the 2006 data starts from 25 March.

The calculation for the generation-weighted price is as follows:

Average daily 'take' * Average daily price at HKK node / (Sum of daily 'takes' for year/366)

The resulting generation-weighted prices are represented in the 'duration curve' below, which shows the percentage of time in the year that prices received by the Waitaha scheme for its output would be at given levels.

Figure 48: Duration curve for Waitaha generation-weighted prices – 2006 to 2012
Source: Author using Westpower and Electricity Authority data



In the six sample years (2006 to 2012), generation-weighted prices were above $80/MWh for 55% of the 2008 year (which was very 'dry' and had the highest average prices), but only 10% of the time in 2009 (which was a 'wet' year and had the lowest average price).

11.6.8 How well would Waitaha power capture higher prices?

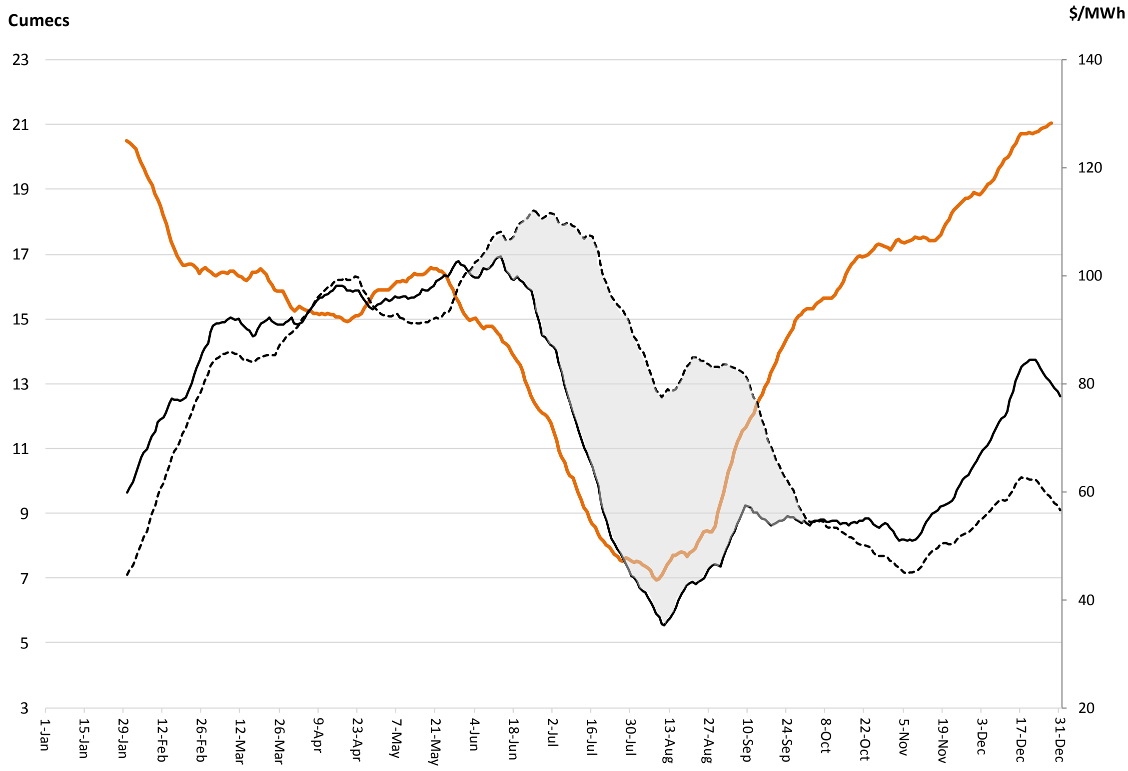
As shown above, the 'take' flows are not well correlated with prices at Westpower's grid exit points – that is to say, when 'take' volumes for generation are high, prices tend to be low; and when 'take' volumes are low, prices tend to be high. (They are well matched on average between March and May).

But how well would Waitaha power capture the full price at Westpower's grid exit points? The answer is, poorly. As shown in the chart below (in the shaded area), Waitaha power would typically miss the normal high price period during winter and early spring.

Figure 49: Waitaha generation-weighted prices relative to prices at Hokitika node and 'take' volumes – 2006 to 2012

Source: Author using Electricity Authority and Westpower data – 25/3/06 to 18/4/12.

Explanation: The dotted black line is the 30 day moving average of prices at HKK0661 (use right hand axis). The solid black line is the 30 day moving average of generation-weighted prices (use right hand axis). The orange line is the 30 day moving average of 'take' volumes for generation (use left hand axis)



This is shown in more detail in the chart below, which 'normalises' the 'durative curve' above, so that the distribution of prices in any year can be compared like-for-like. This shows that, with the exception of 2007, each year is very similar, including the 'wet' year (2009) and the 'dry' year (2008). Waitaha generation only captures the top 50% of prices in a year 2.5% to 10% of the time.

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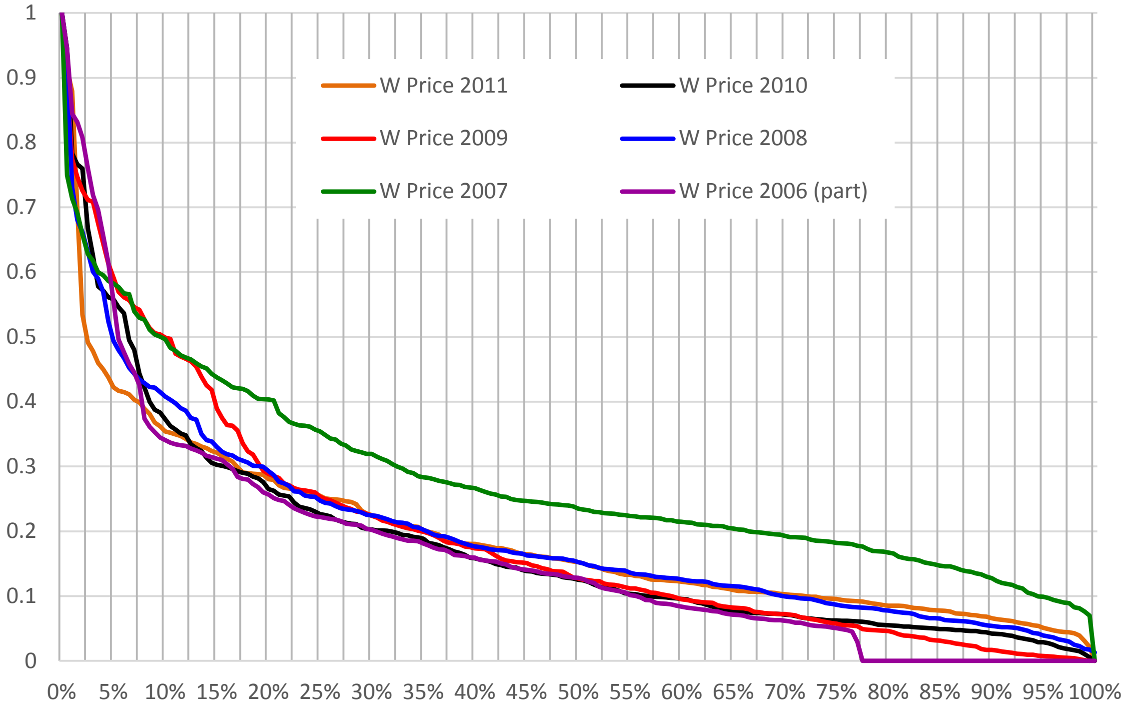
Figure 50: Duration curve (normalised) for Waitaha generation-weighted prices – 2006 to 2012
Source: Author using Westpower and Electricity Authority data



Performance in the 'dry' year of 2008 is illustrative. The chart below shows the difference between the actual (unweighted) average daily price at Westpower's Hokitika node and the generation-weighted price (that is, the price reflecting the daily volumes of water that would have been taken to generate power in the Waitaha scheme). As the chart shows, the generation-weighted price is significantly lower between May and September. In other words, the Waitaha scheme would not capture those higher prices.

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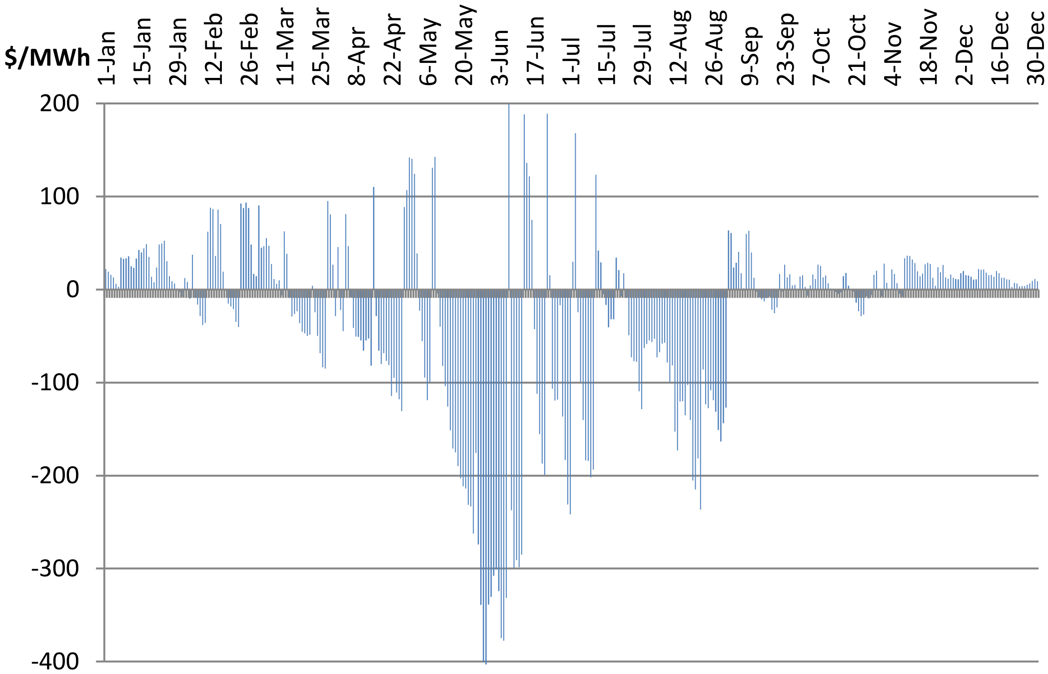
Figure 51: 2008 – Difference between Waitaha-weighted prices and nodal price

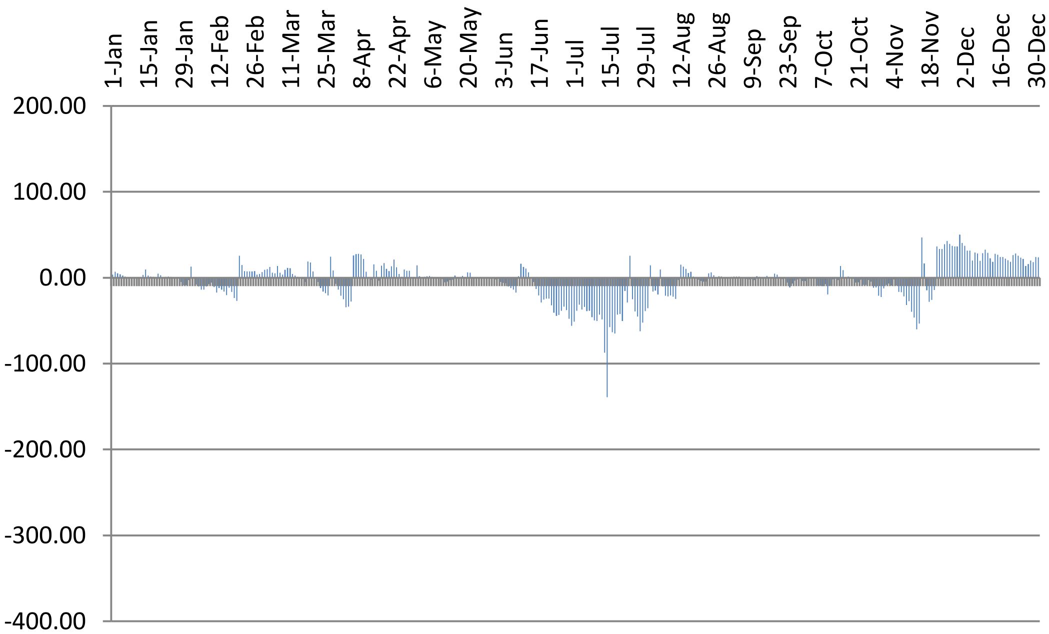
Source: Author using Westpower and Electricity Authority data



As shown in the chart below, the same thing occurs in the 'wet' year of 2009 but the magnitude is much less. (The chart below uses the same scale as the chart above).

Figure 52: 2009 – Difference between Waitaha-weighted prices and nodal price

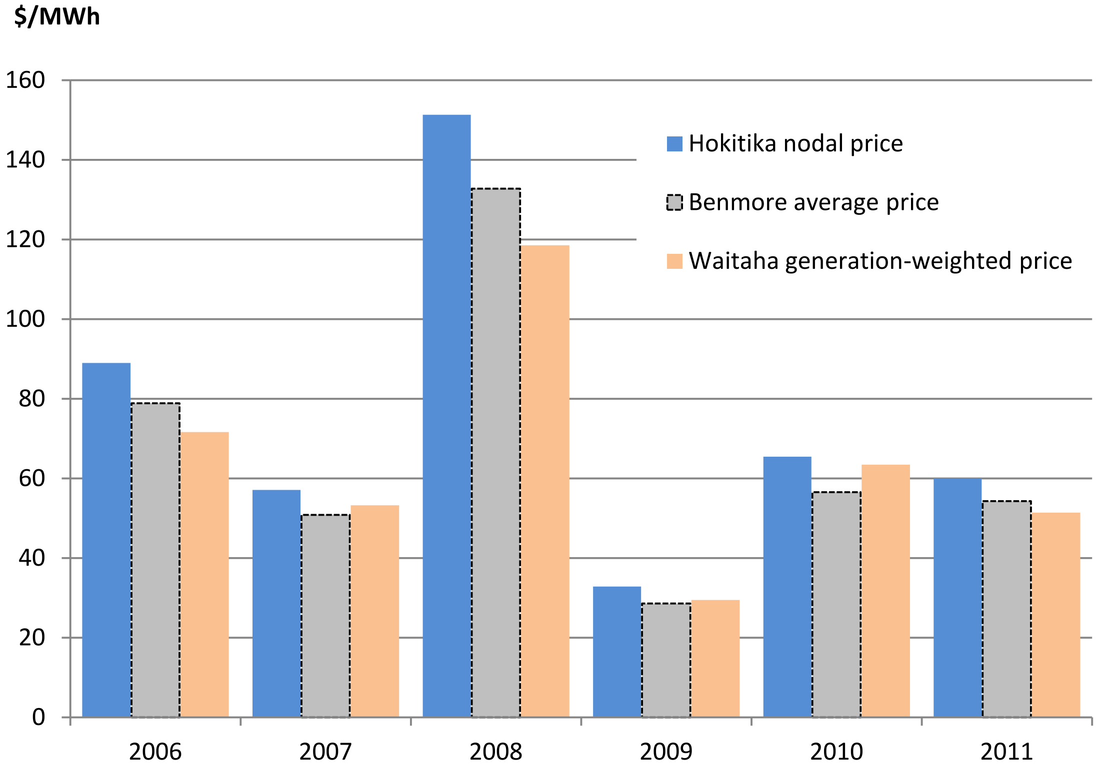
Source: Author using Westpower and Electricity Authority data



Further, the scatter diagrams (plotting the each price for each 'take' volume) for 2006 to 2011 each show a negative correlation. The least negative is 2010. (The data-set for 2012 only goes to 18 April).

It is also interesting to note that, in three of the six years, the Waitaha's generation-weighted prices in the same period (2006 to 2011) are not only lower than prices at the Hokitika node but also lower than prices at Benmore. This is shown in the chart below.

Figure 53: Waitaha generation-weighted prices compared to Hokitika node and Benmore
Source: Author using Westpower and Electricity Authority



Average prices ($/MWh) were as follows:

	Hokitika node:	Benmore node:	Waitaha generation-weighted:
2006 – 2011	$75.50	$69.70	$68.70
2011 - 2014	$75.40	$68.00	[no hydrology data]

This suggests that the Waitaha scheme's annual average generation-weighted price would be reasonably close to projections of annual average wholesale prices at the Benmore node outlined in section 8.5 of this report.

Note that the average Waitaha generation-weighted price for 2006 to 2011 was lower than the average Benmore price for the same period.

11.6.9 Significance for cost of power from Waitaha

To be financially viable, the Waitaha scheme's 'unit cost' – that is, the full cost of producing a unit of power from the Waitaha – must be not greater than the generation-weighted price received for the power (on average over the medium term to longer term). As shown above, the Waitaha's generation-weighted prices are lower on average than average prices at Westpower's grid exit points and, in some years, also lower than average prices at Benmore. This sets a more demanding ceiling on the proposed scheme's 'unit cost'.

11.7 Unit cost of Waitaha power

11.7.1 Overview

As outlined above, the key components of the unit cost for an electricity generation scheme are its variable operating and maintenance costs (**VOM**), fixed operating and maintenance cost (**FOM**) and capital costs, all expressed relative to electricity output:

Unit Cost ($/MWh) = **FOM** ($/MWh) + **VOM** ($/MWh) + **Capital charge** ($/MWh)

'Unit Cost' is sometimes loosely referred to as a 'project's LRMC'.

11.7.2 FOM and VOM

Westpower has not disclosed its estimated VOM and FOM for the proposed Waitaha scheme. However, as noted above, operating and maintenance costs for hydro generation are comparatively low as a proportion of the unit cost. MBIE's model uses Parsons Brinckerhoff's estimates of VOM and FOM for hydro generation as follows:

- VOM = $0.85/MWh
- FOM = $1.46/MWh.

These values were set as at 2011. If the Producer Price Index scalar for 2011 to 2014 is applied (1.0352), those values would increase slightly.

As noted in section 9 of this report, Parsons Brinckerhoff estimates used a target 'concept' level of accuracy of +/- 30%. Therefore VOM and FOM together could be up to around $3/MWh, which represent around 2.5% to 3.6% of unit cost for the top eight new hydro generation options as ranked by lowest project LRMCs in MBIE's model.

For the purposes of estimating the unit cost of the proposed Waitaha scheme, the Parson Brinckerhoff VOM and FOM costs above have been used.

11.7.3 Capital charge methodology

Westpower has not disclosed its estimated capital charge for the proposed Waitaha scheme. As noted above, the capital charge is the total capital cost amortised over an appropriate economic period using an appropriate discount rate.

Deriving a reasonable estimate requires several input variables. The level at which those variables are set can have a significant impact on the level of the capital charge. Total capital cost and cost of capital are discussed further below. However, in the absence detailed project data, a reasonable desk-top proxy is to derive a capital charge for the Waitaha scheme that would enable its unit cost ('project LRMC') to be compared on a like-for-like basis with hydro generation proposals in MBIE's 2015 LRMC rankings, which are set out in sections 9.7 and 13.5 of this report.

The methodology is as follows:

- For each of the eight hydro projects in MBIE's 2015 LRMC ranking table:
    - Calculate the capital charge component (that is, LRMC less VOM and FOM in $/MWh), then
    - Calculate typical GWh per $m of estimated capital cost, then
    - Plot GWh per $m against the $/MWh capital charge component (this gives a reasonably linear relationship for the eight)
- Then, using the parameters of the linear equation –
    - Estimate the capital charge of the Waitaha scheme, and then
    - Add the estimated capital charge for the Waitaha scheme to the estimates of FOM and VOM. The total gives an estimate of the Waitaha scheme's unit cost (or project LRMC) on a basis that is consistent with the MBIE's LRMC rankings.

The estimated capital cost and some other variables of the Waitaha scheme can then be "flexed" to gauge the effect on the scheme's unit cost (or project LRMC) as a desk-top sensitivity analysis. The results are set out below.

11.7.4 Estimated unit cost of electricity from Waitaha scheme

Applying the methodology outlined above, the Waitaha scheme's estimated unit cost ranges from **$94.78**/MWh to **$109.90**/MWh.

On MBIE's 2015 rankings:

- A unit cost of $94.78/MWh would put the Waitaha scheme about **9th** from the top out of 28 projects (where top is the least cost and bottom is the highest cost). This assumes the Waitaha's capital cost totals $95m and it delivers 120 GWh pa.

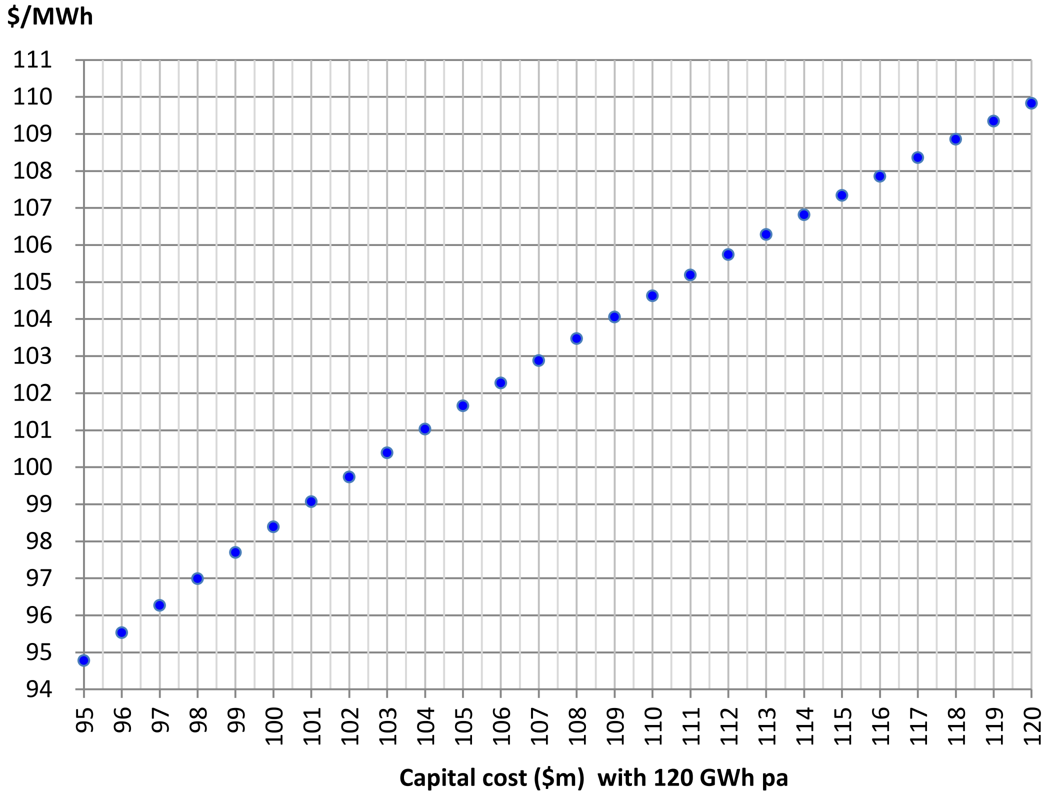
- A unit cost of $109.90/MWh would put the Waitaha scheme about **26th** from the top out of 28 projects (where top is the least cost and bottom is the highest cost). This unit cost comes about under various scenarios, including:
    - Total capital cost of $120m and 120 GWh pa;
    - Total capital cost of $115m and 115 GWh pa; or
    - Total capital cost of $100m and 110 GWh pa.

Varying the total size of the plant between 116 to 120 MW changes the unit cost by 21 cents/MWh – it is not material.

However, variations in the capital cost and annual output (GWh) has a significant impact on capital charge and therefore unit cost (or project LRMC). This is shown across some ranges in the following charts.

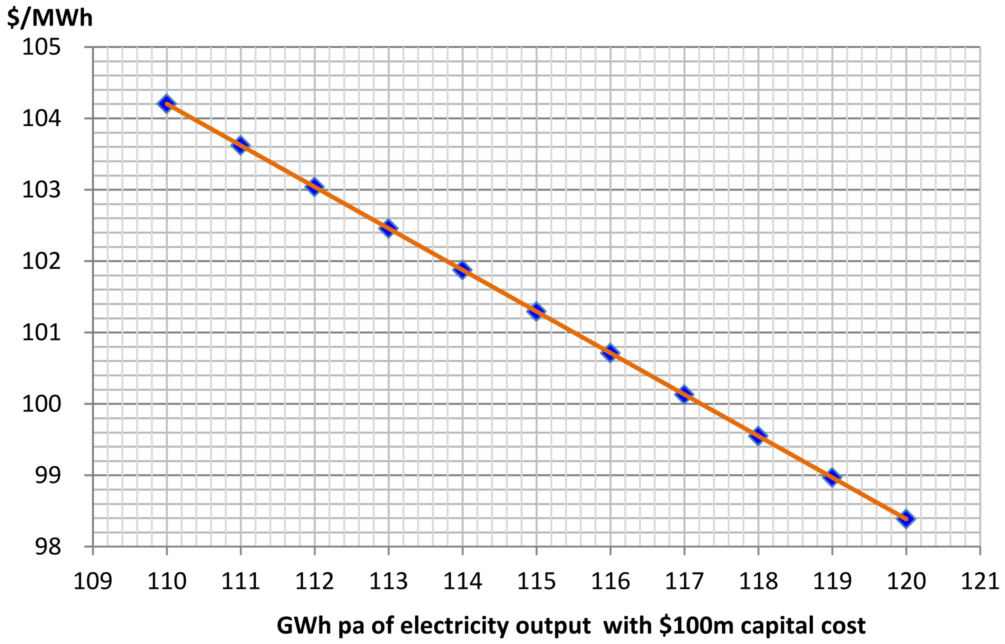
The first chart below shows how the Waitaha's unit cost (project LRMC) varies with changes in capital (holding GWh of output constant at 120GWh).

Figure 54: Waitaha estimated unit cost with changes in capital cost only.
Source: Author derived on MBIE data framework
Explanation: Assume 120 GWh pa for each capital cost point



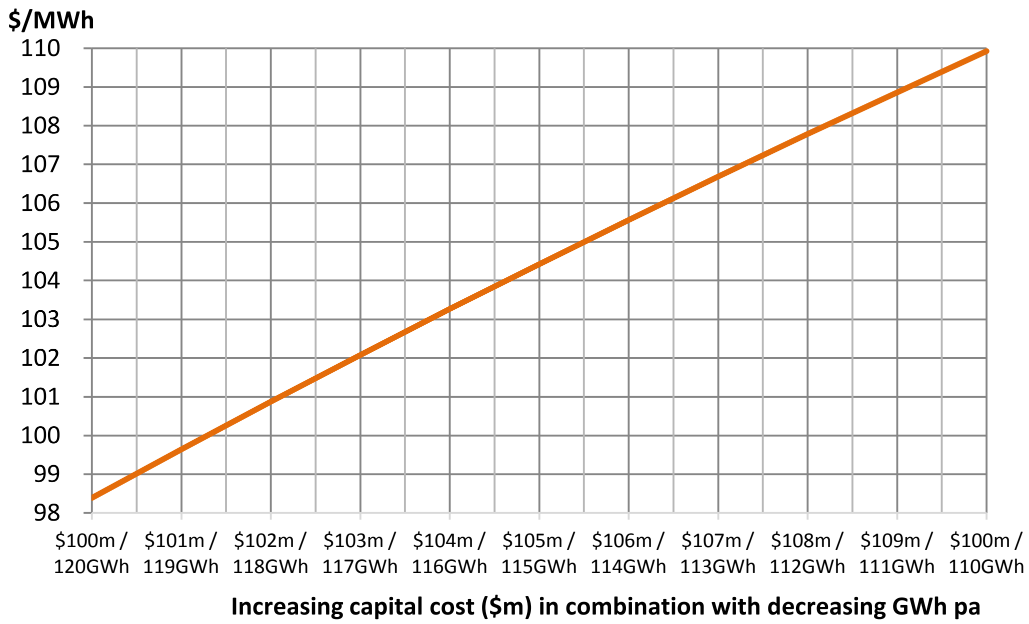
The next chart below shows how the Waitaha's unit cost (project LRMC) varies with changes in GWh pa of output (holding the capital cost constant at $100m).

Figure 55: Waitaha estimated unit cost with changes in GWh pa.
Source: Author derived on MBIE data framework
Explanation: Assume $100m capital cost for all levels of GWh pa



Finally, the chart below shows how the Waitaha's unit cost (project LRMC) varies with changes in GWh pa of output in combination with changes in capital cost.

Figure 56: Waitaha estimated unit cost with changes in capital cost and GWh
Source: Author derived on MBIE data framework
Explanation: Increasing capital cost with decreasing GWh pa



11.7.5 Relationship between unit cost, capital cost and output level.

The above analysis shows that:

- The Waitaha scheme's unit cost is sensitive to its capital cost and level of electricity output (GWh pa):
  - As the scheme's capital cost rises, so does its unit cost (by about 75 cents/MWh for a $1m increase in capital costs. The rate of increase in unit cost decreases as capital cost gets higher. This assumes no change in GWh pa).
  - As electricity output (GWh pa) declines, the scheme's unit cost increases (by about 58 cents/MWh for each GWh decline. This assumes no change in capital cost).
  - As capital cost increases and GWh pa decreases as a combination, the scheme's unit cost increases more sharply – that is, by $1.25/MWh for a combination of a $1m increase in capital cost and a 1 GWh pa decrease in output. The rate of this increase in unit cost decreases as capital cost gets higher).

11.7.6 Waitaha's capital cost

Total capital cost includes the direct costs of all plant, materials, equipment and buildings, all labour costs associated with construction, installation and commissioning, as well as owner's costs such as land, development approvals, legal fees, inventories, and the like. The total cost should also include the costs of connection to the network.

The total capital cost of the Waitaha project is not known. Westpower will have a range of estimates based on its feasibility work. However, the total cost is unlikely to be known within a narrower range (of say +/-15%) until more detailed design and assessment work has been completed.

While the Waitaha project has some design and engineering similarities to the Amethyst scheme, a range of different location-specific factors mean that care must be taken in assuming that the Amethyst cost parameters necessarily carry over on a scaled basis.

As noted in section 3 of this report, the proposed scheme could also require a significant upgrade to the Waitaha substation and associated distribution lines[221]:

> "The Hokitika to Harihari 66 kV line was purchased from Transpower in 2001 but has only been running at 33 kV since 1993, when a physical optimisation took place. A new generation scheme at Waitaha in South Westland, tentatively planned for 2018/2019, will involve recommissioning the line at a 66 kV voltage level, and upgrading the existing conductor and the connected substations from 33 kV to 66 kV".

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[221] Westpower's Asset Management Plan 2014-2024, section 3.12, page 105

http://www.westpower.co.nz/system/files/resources/AssetManagementPlan2014_0.pdf

Transpower has signalled an issue to be addressed with further embedded generation on the West Coast:

> "Under light load and high West Coast generation conditions high voltage will occur on the 110 kV transmission system. This issue can be easily managed operationally at present. If there are increased levels of embedded generation, this issue will become more significant and may require more intensive operational control of the generating units' voltage set-points."[222]

The only public information found to date of the Waitaha's indicative capital cost is a report on "Energy and Business News" dated 23 November 2012, which states:

> "According to Electronet's project manager Roger Griffiths, it is anticipated the project will begin in 2014 with construction starting around mid 2015. The hydro power plant expected to be operating by late 2016. The Waitaha project is forecast to cost around USD$80 million. Upon completion, the hydro power plant will generate around 110-120GWh per year...The Amethyst River hydro power plant is expected to be commercially operating by April next year and will cost approximately USD$40 million."[223]

If the USD$80 as at 2012 is converted New Zealand dollars at the exchange that applied in 2012 and a Producer Price Index scalar is applied to express it in 2014 New Zealand dollars, the reported cost of the Waitaha project would be **NZ$101m.**

11.7.7 Conclusions in relation to Waitaha's unit cost

If the scheme's capital cost was $100m and its output was 120 GWh pa, its unit cost (or 'project LRMC') would be about **$98.39** using the MBIE framework. This would put the Waitaha scheme about **13th** from the top out of 28 projects (where top is the least cost and bottom is the highest cost), 20 of which are already fully consented.

As noted below, $100m is the estimated capital cost of the Waitaha scheme reported in 2012 (converted into NZ$2014).

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[222] Transpower's 2014 Annual Planning Report, section 16.10.1 at page 251

[223] "Energy and Business News" dated 23 November 2012 - http://www.energybusinessnews.com.au/energy/hydropower/new-hydro-for-nz-south-island/

Figure 57: Approximate ranking of Waitaha in MBIE framework
Source: Author using MBIE data

Rank	Type	Project	Fully consented	MW	Typical GWh pa	Capital cost $m	Variable O&M,	Fixed O&M,	LRMC $/MWh
1	Geothermal	Tauhara stage 2	Yes	250	1971	1201	0.00	105.00	79.06
2	Gas - CCGT	Otahuhu C	Yes	400	2803	610	4.30	35.00	83.04
3	Hydro	Hawea Control Gates	Yes	17	74	53	0.86	6.38	87.49
4	Wind	Hauauru ma raki stage1	Yes	252	975	627	3.00	50.00	89.43
5	Wind	Hauauru ma raki stage2	Yes	252	975	627	3.00	50.00	89.43
6	Hydro	Lake Pukaki	Yes	35	153	114	0.86	6.38	90.45
7	Gas - CCGT	Rodney CCGT stage 1	Yes	240	1682	384	4.30	35.00	91.27
8	Gas - CCGT	Rodney CCGT stage 2	Yes	240	1682	384	4.30	35.00	91.27
9	Wind	Turitea	Yes	183	708	478	3.00	50.00	94.91
10	CCGT	PropopsedCCGT1	Proposed	194	1360	333	4.30	35.00	95.01
11	Wind	Hawkes Bay windfarm	Yes	225	780	560	3.00	50.00	96.68
12	Geo	Tikitere LakeRotoiti	Applied	45	355	303	0.00	105.00	97.53
13	Hydro run of river	Waitaha	No	20	120	100	0.86	6.38	98.39
14	Wind	Project CentralWind	Yes	120	416	314	3.00	60.00	99.05
15	Hydro	Arnold	Yes	46	201	192	0.85	6.38	99.51
16	Hydro	Lake Coleridge 2	Applied	70	307	289	0.85	6.38	102.4
17	Hydro run of river	Stockton Mine	Yes	35	153	135	0.80	6.38	103.2
18	Wind	Waitahora	Yes	156	541	408	3.00	50.00	105.5
19	Wind	Puketoi	Applied	159	551	416	3.00	50.00	105.6
20	Wind	CastleHill stage1	Yes	200	693	513	3.00	50.00	106
21	Wind	CastleHill stage2	Yes	200	693	513	3.00	50.00	106
22	Wind	CastleHill stage3	Yes	200	693	513	3.00	50.00	106
23	Geothermal	Rotoma LakeRotoma	Applied	35	276	260	0.00	105.00	106.2
24	Geothermal	Kawerau TeAhiOMaui	Applied	10	79	76	0.00	105.00	107.8
25	Wind	Taharoa	Yes	54	209	166	3.00	60.00	109.2
26	Hydro (SC)	North Bank Tunnel	Applied	260	1139	1045	0.84	6.38	109.2
27	Hydro run of river	Stockton Plateau	Yes	25	110	106	0.86	6.38	111.8
28	Hydro run of river	Wairau	Yes	70	307	297	0.70	6.38	112.1

11.7.8 Caveat

Just as MBIE caveats its model, the estimates above are not necessarily the Waitaha scheme's unit cost. Underlying cost assumptions will vary from one approach to another. The methodology applied in this report compares the proposed Waitaha scheme with other new generation projects in MBIE's model on a 'like for like' basis.

For example, as noted in section 9 of this report, it is widely agreed that Contact Energy's geothermal development option at Tauhara (stage 2) is the next cheapest new generation option. However, market analysts consider its full cost to be close to $85/MWh, rather than $79 as assumed in MBIE's model above. In other words, the threshold price for the next increment of new generation is considered to be higher than MBIE's estimate.

11.7.9 Unit cost of Amethyst scheme

It is interesting to apply the above methodology to Westpower's Amethyst scheme.

Westpower states that its Amethyst scheme is 7.2 MW and produces 45 GWh per year.[224] Its capital cost is reported to have been $35.6m.[225] Based on these assumptions, the schemes unit cost (or 'project LRMC') is estimated to be $96.44/MWh, which would place it 10th on the above table.

The unit cost of such a small scheme is quite sensitive to its capital cost and output level. A lower capital cost and/or higher output would improve (lower) its unit cost and ranking.

Under the above methodology, it would seem to be questionable whether the Amethyst scheme is economic given current wholesale electricity prices.

11.8 Financial viability of Waitaha scheme

11.8.1 Test of financial viability

As outlined earlier in this section, for a new generation project to be financially viable, wholesale electricity prices received over the medium to longer term for electricity sold from the proposed scheme must on average be equal to or greater than its unit cost (or 'project LRMC').

11.8.2 Future prices relative to estimated unit cost

As noted in section 8.5, current projections of medium to longer term wholesale electricity prices are as follows:

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[224] http://www.westpower.co.nz/power-generation-amethyst-hydro.. See also Roger Griffiths, Mitton Electronet - http://www.hydroconference.co.nz/resources/hydro-conference-abstracts-2013.pdf

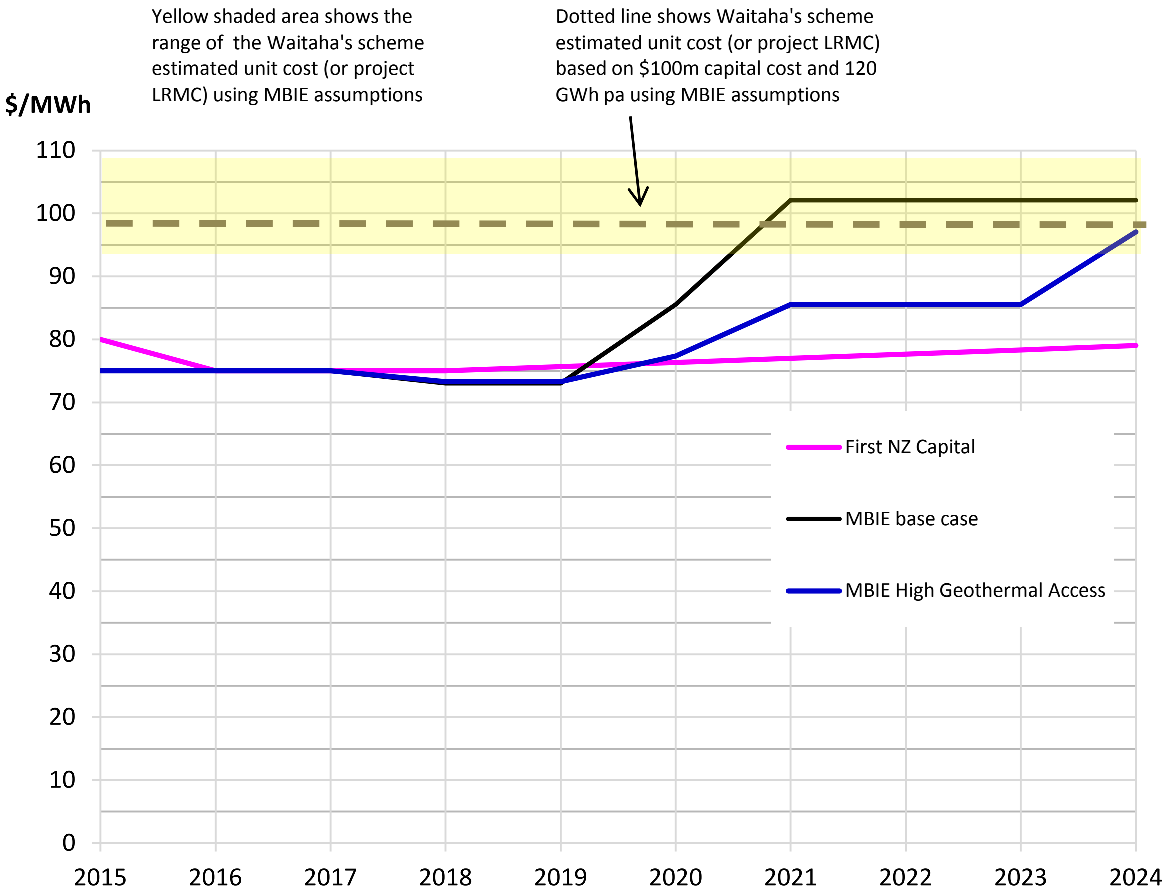
[225] New Zealand Engineering Excellent Awards 2014 - http://www.nzeeawards.org.nz/news/14-11-Celebrating-NZ%27s-talent.cfm

- Until the end of 2019, average wholesale electricity prices are likely to stay at around $73 to $75/MWh
- Beyond 2019, it is not clear:
  - MBIE's draft base case assumes a rise to $102/MWh in 2021.
  - If there is high geothermal availability, MBIE projects a lower more gradual price path with prices not reaching $100/MWh until 2027.
  - Market analysts are projecting a gradual rise from around $75/MWh in 2019 to $80/MWh later in 2025, assuming Tiwai stays open at 400 MW. (If Tiwai continues at 572 MW, price might lift about $5/MWh).

It is important to keep in mind that, as noted below, MBIE's price assumptions are inputs into Transpower's capital expenditure parameters, which is a different context to that of market analysts' projections.

Matching these projections against the above estimates of the Waitaha scheme's unit cost (or project LRMC) is shown in the chart below.

Figure 58: Future wholesale prices v Waitaha scheme's unit cost
Source: MBIE and FNZC projections with author's unit cost estimates



11.8.4 Effect of nodal pricing (transmission losses)

As outlined in section 3.10 and 11.6 above, due to transmission losses wholesale prices at Westpower's grid exit points (also called off-take nodes) are around **8.5% to 13%** higher on average than at the Benmore reference node.[226] At face value, it might therefore be assumed that the price path outlined above might be 8.5% to 13% higher at Westpower's main off-take nodes.

However, as outlined in section 11.6 above, when prices at Westpower's main nodes are adjusted to reflect the Waitaha scheme's expected pattern of generation based on water flows, the higher prices due to transmission losses are cancelled out. The average Waitaha generation-weighted price for 2006 to 2011 was lower than the average Benmore price for the same period.

	Hokitika node:	**Benmore node:**	**Waitaha generation-weighted:**
2006 – 2011	$75.50	$69.70	$68.70
2011 - 2014	$75.40	$68.00	[no hydrology data]

This suggests that the Waitaha scheme's annual average generation-weighted price would be reasonably close to projections of the annual average wholesale price at the Benmore node outlined above and in section 8.5 of this report. This sets a more demanding ceiling on the proposed scheme's unit cost than the unweighted wholesale price at Westpower's key off-take nodes.

11.8.5 Effect of avoided transmission costs

As noted in sections 5.5 and 11.3 of this report, for a new generation scheme to be embedded in the local distribution network, a assessment of financial viability needs to take into account the benefit of any reduction in transmission costs (caused by the proposed new generation) for electricity still purchased from the grid.

Benefits from reduced transmission costs could arise in two ways:

- Payments from Transpower called "Avoided Cost of Transmission Payments" ('ACOT payments'); and
- Possibly lower transmission charges for Westpower (and in turn electricity retailers and consumers to the extent the benefits are passed on) as a result of retailers purchasing lower volumes of power off the national grid (due to volumes supplied directly by the embedded generation).

[226] Assuming that none of the price difference is due to constraints. The Benmore node is the location on the national grid at which Benmore power station injects electricity. Benmore is the southern end of the HVDC link, and if there are no significant intra-island constraints then half-hourly prices at the Benmore node generally reflect the half-hourly prices across the South Island. Benmore is one of the three key reference nodes, along with Haywards and Otahuhu. Source: 2009 Ministerial Review, Volume 2, Appendix 1

The level of any financial benefit for the proposed Waitaha scheme from either is not clear. Westpower currently receives ACOT payments on behalf of Trustpower for generation from its local generation.[227] Since it was commissioned in mid 2013, Westpower has also received ACOT payments for generation from the Amethyst scheme. The total ACOT payments are set out in the table below.

Table 11: Avoided Cost of Transmission Payments ($000)
Source: Westpower's Information Disclosure to the Commerce Commission for year ended 31 March

2006	2007	2008	2009	2010	2011	2012	2013[228]	2014
0	0	554	964	680	946	1,075	1,075	1,634

It is not clear what level of ACOT payment would be received as a result of the Waitaha scheme's output. It would depend on the degree to which Waitaha generation would reduce Westpower's regional coincident peak demand (RCPD) each month.[229]

However, the future of ACOT payments is uncertain. The Electricity Authority is currently proposing to change the payment methodology to one based on avoided economic costs, rather than avoided transmission charges.[230] The Electricity Authority is concerned that ACOT payments appear to have increased costs to consumers by about $10 per household per year. This is part of a broader review of the transmission pricing methodology in general.

As noted in section 6.7.2 of this report, Westpower's forecasts indicate that the addition of the Amethyst scheme is expected to cause the equivalent of around 55% of its output to be exported out of the region.[231] It is not clear what proportion of the Waitaha's output would be exported rather than used to reduce volumes from the grid.

In any event, interpolating the ACOT payments stream above (assuming they continue), it is reasonable to assume that the financial benefits to the Waitaha scheme (or other parties) of

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[227] Trustpower's local stations are set out in section 10.5.2 of this report

[228] Estimate based on 2012 value as 2013 value is not disclosed in Westpower's 2013 Information Disclosure or Annual Report

[229] Of the 29 distributors, 23 have an ACOT payment policy. Transpower advises that ACOT payments by the local lines company to the embedded generator are determined by the lines company in question. Many base it on their avoided transmission (RCPD) charge which would mean the payment received by a generator would be: interconnection rate (IR) x kW / # of RCPD peaks. That is to say, a generator who reduced a distributor's RCPD peak by 1MW for one (of 12) RCPD peaks might expect to receive $114 (IR) x 1000kW / 12 = $9,500. If the generator was generating for all 12 RCPD peak periods then they would receive $114,000 (12 x $9,500 or $114*1000).

[230] The Electricity Authority has issued a working paper dated November 2013 "to understand the efficiency implications of any changes to the TPM in relation to ACOT payments", received submissions on it, and issued a summary of submissions dated 8 September 2014.

[231] Westpower's Information Disclosure of 2014 indicates that until 2014, electricity supplied from distributed generation was steady at around 88-91 GWh pa. From 2015 onwards, Westpower forecasts that distributed generation will produce about 137 GWh of which about 25 GWh will be exported. If the Amethyst generates around 46 GWh pa, this indicates that around 55% of its output will be exported (unless the 25 GWh to be exported comes from Trustpower's local generation). Either way, the addition of the Amethyst is expected to cause the equivalent of around 55% of its output to be exported out of the region.

any avoided or reduced transmission charges are not likely to change the assessment above and below of the Waitaha scheme's financial viability.

11.8.3 Is it likely to be financially viable in the next five years?

Applying the test outlined above, is the average wholesale electricity price over the next five years expected to be equal to or greater than the Waitaha scheme's estimated unit cost (or 'project LRMC') of between $94.78/MWh and $109.90/MWh? Based on the price paths set out above, the answer is no.

Based on the analysis set out above, it is therefore unlikely that the proposed scheme would be financially viable in the reasonably foreseeable future.

11.8.4 When is it likely to become financially viable?

It depends on three key factors (among others):

- **Future wholesale electricity prices:** Whether wholesale prices rise from 2020 and, if they do, the rate at which they rise is one of the key factors. This is discussed further below.

- **The level of the scheme's capital cost:** As outline above, the scheme's unit cost has been estimated for a range of capital costs, from $95m to $120m. This is based on a reported capital cost of USD$80 as at 2012, which is NZ$101m when converted to 2014 New Zealand dollars (at the exchange that applied in 2012 with a Producer Price Index scalar applied). It is reasonable to assume that capital costs are more likely to rise than fall over the coming years. As shown above, relatively small increases in capital cost increase the scheme's unit cost, which means a higher average wholesale price would be required for the scheme to be financially viable.

- **The level of electricity output that the scheme would produce:** As shown above, relatively small decreases in assumed output increase the scheme's unit cost, which means a higher average wholesale price would be required for the scheme to be financially viable.

Future wholesale electricity prices are perhaps the key driver. As outlined in this report, there is a reasonably clear consensus, which has been in place for the last two years or so, that wholesale prices are likely to remain flat for the medium term, particularly given low demand growth and continuing surplus capacity, as outlined in section 8.5 of this report.

Beyond 2020, the price path is not clear:

- Under MBIE's draft base case scenario, the Waitaha scheme could become viable from around 2021.

- Under MBIE's high geothermal availability scenario, it would not become viable until 2024 or even 2027.

- Under First NZ Capital's wholesale price projection, it would not be economic even by 2024.

In reality, prices beyond 2020 are too uncertain to forecast with any confidence. Some of the relevant factors are outlined in section 8.5 of this report. At best, any current view of prices beyond 2020 is simply a scenario (one of many) against which changes in the market can be monitored.

What can be reasonably concluded now in relation to the Waitaha scheme's financial viability beyond 2020 is this:

- For it to become viable around 2021 would require a relatively sudden and substantial rise in wholesale prices – in the order of 30% on current prices.

- Such a substantial rise over such a short duration would seem unlikely based on current information and previous patterns of structural change in medium to longer term wholesale prices.[232]

- There are a significant number of fully consented new generation projects that appear to have materially lower unit costs than the Waitaha scheme.

- It would not be sensible, for the New Zealand electricity system or electricity consumers on Westpower's network, for the Waitaha scheme to be built ahead of new generation options with a lower unit cost.

- As the 2009 Ministerial Review observed: "It is important to minimise the costs of new generation, get the right generation built, and ensure that alternatives such as energy efficiency are fully exploited."[233]

11.8.5 Conclusion on financial viability

Based on the analysis in this report, the Waitaha scheme is not likely to be financially viable in the reasonably foreseeable future.

11.9 Other related matters

11.9.1 Cost of capital

As outlined above, this report has applied regression analysis to derive and compared the Waitaha's scheme's unit cost against the unit costs of other new generation projects in MBIE's LRMC ranking model. This obviated the need to establish and apply a cost of capital for the Waitaha scheme. However, in a full discounted cashflow analysis, cost of capital is a key

[232] See 2009 Ministerial Review, Volume 1, Figure 8 at page 40

[233] "Ministerial Review of Electricity Market Performance", Electricity Technical Advisory Group and the Ministry of Economic Development, August 2009, Volume 1, para 54

factor. In the methodology outlined above – where unit cost (or project LRMC) is the sum of VOM, FOM and capital charge – it is ordinarily also significant. For completeness, therefore, this part of the report briefly discusses cost of capital

11.9.2 Definition

"Risk-averse investors require recovery of capital costs with a suitable premium for risk, as well as the fixed and variable operating costs they incur in operations."[234] This in essence is the cost of capital. It is the opportunity cost of capital used in the new generation project; that is, the return foregone by investing in one project rather than in an alternative project with the same level of risk.[235]

As Treasury notes, the main tool used to calculate this discount rate is the capital asset pricing model (CAPM). Even in the public sector, the usual approach is to estimate the expected return from alternative investments in the private sector.[236]

11.9.3 Relevant reference points

Estimating any cost of capital is complex and can be difficult. It is involves a range of technical assumptions that are not precise. It involves nuanced judgement of how the market will view various risks in different markets and various time-frames.

A range of reference points can be used, including cost of capital calculations by:

- Research analysts of listed generator/retailer companies;
- One of the generator/retailer companies directly;
- Treasury in relation to its cost of capital assumptions; and
- Commerce Commission in relation to regulated electricity distribution businesses.

11.9.4 WACC formula

The following formulae would have been used to estimate the weighted average cost of capital:

Cost of debt =	(Risk Free Rate + Debt Premium) x (1- Effective Corporate Tax Rate)

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[234] "A Critique of Wolak's Evaluation of the NZ Electricity Market: Introduction and Overview", Prof Lewis Evans, Seamus Hogan and Peter Jackson, Working Paper No. 08/2011 at page 9

[235] This is so even in the public sector – see "Public Sector Discount Rates for Cost Benefit Analysis", July 2008, Treasury

[236] Cross-checks include the Discounted Cash Flow (DCF) model for equity valuation and Arbitrage Pricing Theory (APT) models, the most common of which is the Fama-French three-factor model - Recommendations to the New Zealand Commerce Commission on an Appropriate Cost of Capital Methodology, Franks, Lally, Meyers, December 2008

Cost of equity = (Tax-adjusted Market Risk Premium x Equity Beta) + [Risk Free Rate x (1 – Investor Tax Rate)]

WACC = (Leverage ratio x Cost of Debt) + ((1-Leverage ratio) x Cost of Equity)

11.9.5 Cost of capital for electricity generation business

Based on the most current and relevant of the above reference points, the low and high ends of the key parameters are set out in the table below. The assumptions used by First NZ Capital as at February 2015 in estimating a generic cost of capital for generator/retailers in the sector are also shown.

Table 12: Cost of capital for electricity generation:
Source: FNZC, Commerce Commission, other

	Low	**High**	**First NZ Capital**
Risk free rate	4.40%	5.00%	5.00%
Debt premium	2.10%	2.75%	2.75%
Leverage ratio (debt/(debt+equity)	30%	35%	30%
Equity beta	0.88	0.95	0.88
Tax adjusted (equity) market risk premium	7.00%	7.50%	7.00%
Corporate tax rate	28%	28%	28%
Investor tax rate	28%	28%	28%
Cost of debt (post tax)	4.70%	5.58%	5.58%
Cost of debt (pre tax)	6.50%	7.75%	7.75%
Cost of equity (post tax)	9.77%	10.37%	9.75%
Cost of equity (pre tax)	11%	11.77%	11.16%
WACC (post tax) (nominal)	8.03%	8.93%	8.50%
WACC (pre tax) (nominal)	9.43%	10.56%	10.14%

In its LRMC ranking model, MBIE uses a discount rate of 8% post tax real, which in nominal terms would appear to be higher than the WACC above.

11.9.6 Comment on cost of capital

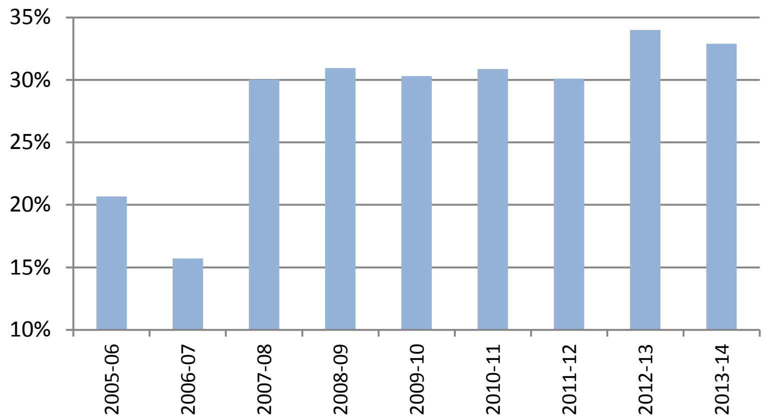
The low end variables reflect a relatively short term view of the risk free rate, debt premium and market risk premium. However, leading sector analysts are expecting a return to the long-run risk free rate of 5% and a similar adjustment in the debt premium. The longer run view is more appropriate to a project with a longer economic life such as the Waitaha.

The consensus equity beta[237] for generation/retail companies seems to be 0.88, although there is a view among some analysts that it is higher.

The leverage ratio is influenced by a range of factors. For companies with a credit rating, the top end is strongly influenced by credit rating agency requirements for the company to preserve its target rating. Key parameters for this purpose include the FFO/debt ratio and the FFO interest cover (FFO refers to funds from operations). For an unlisted company, lenders are concerned about the same underlying issues, in particular the company's capacity over time to pay interest and return principal as and when the lender requires, while still meeting the company's strategic objectives.

As shown in the chart below, Westpower's leverage ratio has been around 30% since 2007-08. In the last five years, Westpower has funded a larger proportion of its debt from shorter term borrowings, as shown in the chart below of current and non-current liabilities. In the same period, its ratio of current assets to current liabilities has been negative, as shown in the chart below of operating liquidity. These levels reflect the period during which Westpower was building and commissioning the Amethyst scheme, which is a relevant parallel.

Figure 59: Westpower – leverage ratio (debt to equity + debt)



[237] The beta coefficient is a measure of the sensitivity of an asset's return to that of the market portfolio. A beta of one means that the expected return of the investment always moves with the market as a whole; a beta of zero means that the expected return of the investment is independent of the market.

Figure 60: Westpower - ratio of current and non-current liabilities

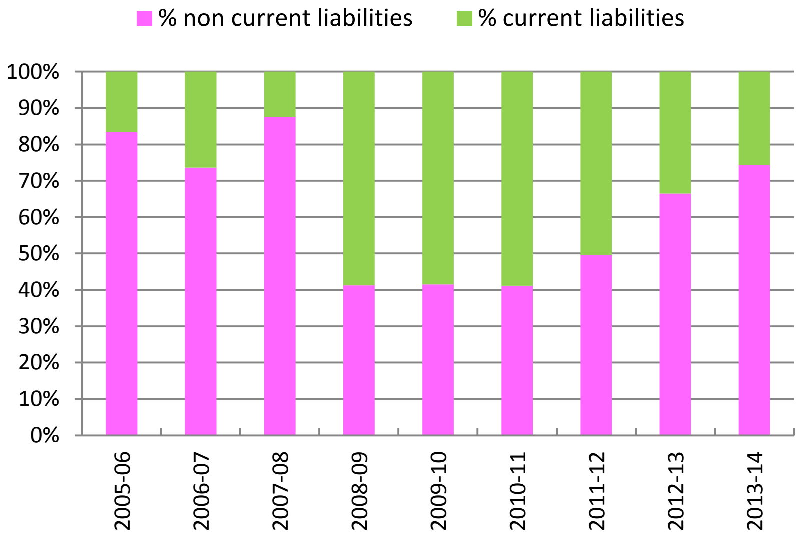
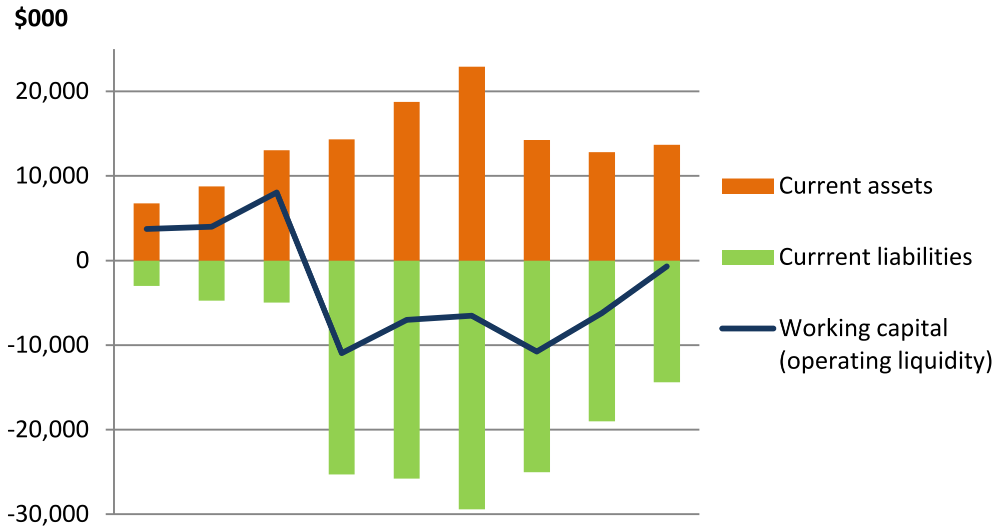


Figure 61: Operating liquidity, 2005/6 - 2013/14



On balance therefore, and taking into account the risks of the project, which are outlined above, a leverage of around 33% would seem to be appropriate for the purposes of estimating the cost of capital relevant to Westpower's Waitaha scheme.

11.9.7 No grounds for artificially lowering cost of capital

Westpower may assert that a lower pre-tax discount rate should be used, which would lower the cost of capital and, in turn, lower the unit cost of the Waitaha project. Among other things, Westpower may say that, as a monopoly lines distribution business, its cost of debt and equity is lower and this should be reflected in the risk profile of the Waitaha scheme.

Westpower also may argue that it can use a cost of capital close to the rate set by the Commerce Commission for regulated electricity distribution companies (their default rate for 2015 to 2020 is 7.19%). Alternatively, Westpower could argue that it can use a rate that is an average of its lines business' cost of capital and the rate that would apply if the Waitaha project were treated on a stand-alone basis.

Neither approach would be appropriate. Both would fail to reflect the opportunity cost of capital used in the Waitaha project; that is, the return foregone by investing in one project rather than in an alternative project with the same level of risk.

As noted above, from an economic and regulatory stand-point, the Waitaha scheme is a separate business, the viability of which is to be assessed on a stand-alone basis. Westpower should not rely on support from its other businesses to enable or sustain the generation business. Unlike its lines business, Westpower is not assured of recovering all costs from power consumers. Nor can it control the price it charges. As outlined above, the risks in electricity generation are both substantially different and higher.

Nor is there any need to artificially lower, or make a special case to lower, the discount rate to enable provision of a service that has a special need or would not otherwise be provided.[238] As outlined in sections 9 and 13 of this report, there are numerous new generation schemes in the wings ready to be built as and when demand growth requires.

11.9.8 Risks in electricity generation

The risks in significant new generation investment are diverse, complex and considerable. For the Waitaha proposal, these risks include:

- **Capital cost of scheme** – The risks in building a 1.5km tunnel-based scheme are substantial. Any material cost over-run increases the level of the capital charge, which in turn increases the scheme's unit cost. For a scheme with a unit cost close to average wholesale electricity prices at the relevant grid exit point, cost over-runs can easily turn a scheme from just viable to non-viable. The cost of construction includes mechanical (turbines, generators and the like), electrical (transformers, switchgear and the like), civil (buildings, dams, earthworks and the like), engineering design, legal and financial costs including interest during construction, land and consenting costs.[239]

- **Generation output** – Revenues depend on the volume of output over time from the scheme. Lower-than-expected output is one of the major risks. This could be caused by a range of factors, including lower-than-expected efficiency in any part of the scheme, adverse water inflows, unplanned operational interruptions and the like. The amount of electricity produced by the scheme for each unit of water taken is a function of various engineering and design factors, including the height of the head, friction in the tunnel and

[238] Even in the public sector, lower discount rates are only to be used only in exceptional circumstances – see "Public Sector Discount Rates for Cost Benefit Analysis", Treasury, July 2008, at section 3.3.1 page 29s

[239] "2011 NZ Generation Data Update", Parsons Brinckerhoff, 26 January 2012, at 2.1.5

penstocks, and the efficiency of the plant. Generation efficiency is also a function of the capacity at which the plant operates relative to its potential capacity.

- **Hydrology relative to prices –** The timing and quantities of water inflows available to take for generation relative to changing wholesale electricity prices at Westpower's grid exit points is a pivotal factor in the scheme's financial viability, particularly as run-of-river schemes are not able to store water or manage the timing of inflows relative to wholesale prices, which change every half hour. Further, the risk of a 'dry year' (a period of sustained low inflows) is a material risk and could have a major adverse effect. (Hydrology is discussed further below).

- **Wholesale electricity prices and demand** – Revenues also depend on electricity prices received over time on electricity sales. Lower-than-expected wholesale electricity prices over time are another major risk in the project. Its financial viability depends at a fundamental level on electricity sales receiving prices over the medium to longer term that deliver an appropriate risk-adjusted return on the investment. Lower-than-expected prices could be caused by a wide range of factors, including sustained warmer temperatures, increased energy efficiency, and lower-than-expected economic activity.

- **Managing market risks** – Failure to properly manage electricity price and other related market risks over time is another material risk for the project. Without a matching electricity retail business, revenues from the scheme will be strongly influenced by the nature and extent of any contracts and hedging arrangements that Westpower puts in place with retailers. Poor decisions in relation to such contracting are a material risk for the project's viability.

- **Cost of capital** – In hydro generation, cost of capital is the major component (around 95%+) of unit cost. Adverse changes in the cost of capital is therefore another key factor in whether or not the project is financially viable. As outlined below, any assessment of a project's cost of capital needs to reflect the expected cost of debt and equity over the economic life of the project.

- **Regulatory risks** – The electricity industry is exposed to material risk of change in regulatory environment in which it operates. This includes economic and non-economic regulatory risks and political risk, with potential adverse impacts on costs, financing conditions and earnings.

In New Zealand's wholesale electricity market, the level of future prices is an extremely significant risk for any investor in new generation, but particularly for stand-alone new hydro generation. While hydro generation may have low short-term costs of production, it has comparatively high fixed capital costs. Adequacy of revenue to cover those costs is particularly exposed to the risk of lower-than-expected wholesale prices over the medium term.[240]

[240] "Power Generation Investment in Electricity Markets", International Energy Agency, 2003 (OECD)

These risks are part of any new hydro generation project to varying degrees and inform the risk assessment reflected in the project's cost of capital.

11.9.9 Not rely on lines or other businesses

Westpower has very limited ability to properly manage electricity market risks, particularly given the absence of an integrated retail market hedge, no meaningful diversity in its generation portfolio, and a run-of-river scheme in which the hydrology appears to parallel the large hydro generators on the Waitaki river. This would suggest a risk profile for Waitaha scheme that is higher relative to generators with a portfolio of stations, some ability to store water, and a retail market hedge through vertical integration.

Westpower may say that it has the capacity to absorb these risks with its monopoly lines business and its other activities. However, as outlined further below, this would not be at all appropriate. From an economic and regulatory stand-point, the Waitaha scheme is a separate business, the viability of which is to be assessed on a stand-alone basis. Westpower should not rely on support from its other businesses to enable or sustain its generation business.

In any event, Westpower relying on its lines and contracting businesses to absorb the major risks involved in a new stand-alone generation scheme would not reduce the risks inherent in the scheme. They would still be present and require an appropriate level of return to satisfy the opportunity cost of the resources deployed in the project.

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12. Westpower's reasons for Waitaha scheme

12.1 Outline of this section

This section 12 is divided into the following parts:

- Summary of key points
- Statutory requirement to give reasons
- Overview of Westpower's reasons
- Meeting rising demand for electricity
- Self-sufficiency
- Community ownership
- Security of supply
- Transmission losses
- Confidence to investors in the West Coast
- Reduce carbon emissions
- Conclusion in relation to Westpower's reasons

12.2 Summary of key points

The key points in this section 12 that the reasons given by Westpower for the proposed scheme are either not supported by the evidence and/or not relevant under Part 3B of the Act.

12.3 Statutory requirement to give reasons

As noted earlier, section 17S(2) requires a applicant to supply, in addition to the contents required by section 17S(1):

> "**reasons for the request** and sufficient information to satisfy the Minister, in terms of section 17U, that it is both **appropriate** to grant a lease, *profit à prendre*, licence, or easement and lawful to grant it" [emphasis added]

12.4 Overview of Westpower's reasons

In section 2 of its Waitaha application, Westpower's reasons for the proposed scheme tend to overlap and repeat the same points under different headings. When distilled, Westpower seems to be asserting six reasons for the Waitaha scheme (in no particular order):

- To meet growth in demand for electricity
- Self-sufficiency in electricity and community ownership
- Security of supply

- Transmission losses
- Confidence to investors in the West Coast, and
- Reducing carbon emissions

Westpower's claims in relation to each of these are set out as follow. Comment and (where appropriate) rebuttal are outlined under each point.

12.5 Meeting rising demand for electricity

12.5.1 Westpower's view

At page 118 of its application, Westpower asserts:

> "Peak demand for electricity in the Westpower distribution area has been forecast to grow from 50 MW in 2012 to 70 - 80 MW by 2030, whilst electricity consumption is forecast to grow from 300 GWhs to 400 GWhs per annum by 2030. These growth rate forecasts incorporate possible new mining developments and ongoing growth in dairy farming and milk processing. This will increase the reliance on imported electricity via the national grid in the absence of new generating capacity on the West Coast".

12.5.2 Comment and rebuttal

As set out in section 10 of this report, no information is provided in the Waitaha application to support this forecast, and the application contains no other information in relation to whether additional generation is needed to meet electricity demand.

Further, as shown in the chart in section 10.3.2 of this report, Westpower's demand forecast in its Waitaha application is not consistent with its demand forecasts provided to the Commerce Commission or the demand forecasts of Transpower and MBIE.

As further set out in section 10 of this report, the grounds for Westpower's forecast growth of 20 to 30 MW over the next 15 years appear to be extremely weak. Based on the analysis in this report, and taking into account Westpower's poor track record in forecasting (as outlined in section 6.6 of this report), it is reasonable to conclude that Westpower's long term demand forecast of 70 – 80 MW by 2030 in its Waitaha application is more than questionable and provides no basis for medium term investment in new generation capacity.

Westpower has a current peak capacity surplus of around 38 MW. Applying the growth rate in Westpower's 2014 Information Disclosure, it would take **38 years** to use up this surplus. It would take longer using Transpower's 2014 forecast, and even longer using MBIE's national growth forecast.

Even applying Westpower's aggressive growth forecast in its Waitaha application, the existing surplus capacity would not be used up until around 2034 (**20 years** from now).

Further, as outlined above, Westpower reports that there are no constraints in its network or substations that would limit demand growth.

It is therefore clear that no additional generation capacity is required to meet expected demand growth on Westpower's network.

Further, as outlined earlier and below, the New Zealand system has more than enough capacity to deliver additional power to meet any demand growth on Westpower's network.

In its 2014 Asset Management Plan, Westpower acknowledges:

> "Currently, there is sufficient n-1 transmission capacity available in the transmission network feeding the West Coast, to ensure that major new loads can be supplied on an uninterruptible basis, and so **electricity supply should not be a constraint** to future economic development". [Emphasis added]

Well into the future, at a time when existing supply capacity feeding Westpower's network is becoming insufficient to meet demand, additional capacity can be provided at a relatively low cost by upgrading capacitor banks and the like at grid exit points to enable greater capacity to be delivered on the Dobson transmission lines.

In summary, Westpower's assertion that the Waitaha scheme is required to meet demand growth is not supported by the evidence and does not provide sufficient reason to conclude that it would be appropriate under Part 3B of the Act to authorise an activity in a conservation area that would impose adverse effects.

12.6 Self-sufficiency

12.6.1 Westpower's view

Self-sufficiency in electricity generation on Westpower's network is a recurring theme in Westpower's application to the Minister of Conservation. It is mentioned many times – for example:

> "The Scheme would also significantly increase the percentage of power generated and owned by the local community (from 14% to 54%). This in turn gives the community greater management and control of the electricity assets on which it relies to meet its current and future needs" (page 1)

> "[The Government's 1998 electricity reforms] effectively meant that the local community retained no ability to be self-sufficient in terms of local electricity generation and the management of these resources to meet current and future needs" (page 5)

> "With the Waitaha Hydro Scheme operational, there would be sufficient generation capacity to run all of South Westland and Hokitika" (page 7)

"The Scheme would make the Westpower area almost self-sufficient in power generation. The Scheme would also significantly increase the percentage of power generated and owned by the local community rather than an increased reliance on generation companies with a national focus" (page 8)

"Once operational, and in terms of current annual peak demand this Scheme will make the Westpower area almost self-sufficient thereby reducing the need for, and reliance on, electricity generated and imported from outside the region. The Scheme would also significantly increase the percentage of power generated and owned by the local community. This in turn gives the community greater management and control of the electricity assets on which it relies to meet its current and future needs" (page 9)

"Apart from the Amethyst Hydro Scheme, all other power generation schemes within the Westpower distribution area are owned by Trustpower or NZ Energy, both of which are private companies. Westpower differs from these companies in that it has a focus on providing and managing generation and supply for the benefit of the local community... Westpower's focus is on its own area with a particular interest in ensuring security of supply for consumers" (page 9)

"Moreover, as a community owned company, any profits that are made from the scheme are ultimately directed back to the consumers in the area" (page 8)

"Westpower is a community owned company, and lower costs [including from lower generation costs] will be passed through to local business and residential consumers either via lower retail electricity prices and/or via larger annual rebates to consumers" (page 120)

The degree of potential self-sufficiency is qualified later in Westpower's application:

"Around 50% of peak demand and 52% of electricity consumption must be met with electricity generated outside the region. The Scheme by adding between 16 to 20 MW to local supply could potentially decrease the current reliance on national grid supply from around 25 MW (i.e. about 50% of peak demand) to between 5 to 9 MW (i.e. about 10 to 18% of peak demand), depending on river flows at the time of system peaks" (page 117)

There has been (and perhaps still is) a perception on the West Coast that:

"the Coast has been leading the country in economic development, thanks to its dairy, mining and tourism industries, but it's always been held back to some extent by having to import virtually [all of] its power from elsewhere"[241].

[241] Article in "Energy NZ" Vol.4, No. 4, July-Aug 2010 – "West Coast hydro renaissance" –

http://www.contrafedpublishing.co.nz/Energy+NZ/Vol.4+No.4+July-August+2010/West+Coast+hydro+renaissance.html. See also the article in New Zealand Energy and Environment Business Alert – December 22nd, 2007http://nzenergy-environment.co.nz/home/free-articles/west-coast-electricity-demand-set-to-skyrocket-as-economy-booms.html#sthash.y2C5cfoF.dpuf

12.6.2 Comment and rebuttal

This idea of West Coast self-sufficiency in electricity generation is misplaced. So is Westpower's view that distributed generation is "the most effective and secure way of meeting growing demand for electricity in the South Island".[242] Neither is rational.

"Self sufficiency" is not an end in itself. Nor is it sensible to make it a dominant criterion, which is the case in Westpower's rationale for the Waitaha scheme. Westpower's application dismisses alternatives to the Waitaha proposal that are not embedded.[243]

The notion that the Westpower network should aim to be self-sufficient in electricity generation makes as much sense as arguing that Auckland or any other part of New Zealand should be self-sufficient. It is completely contrary to the reason we have a national transmission grid, which is to provide electricity consumers with access to lower cost generation outside the region in which they live or work.

As Transpower explains:

> "...demand (load) [is] commonly some distance from the areas of significant generation. Consequently, the transmission network is essential in complementing generation to bring the power to where it is needed" [244]

As the 2009 Ministerial Review elaborates:

> "Transmission is at the heart of the electricity market. It enables electricity to be transmitted over long distances from the regions where it is **cheapest to produce** to where it is required."[245] [emphasis added]

A major upgrade of inter-island electricity transmission connection (the HVDC) completed in 2013 means that there are no material technical barriers in transporting power generated in the North Island to the South Island (and vice versa).[246]

As noted in sections 10.5 and 10.6 of this report, with about 50% of a main transmission line feeding Westpower (Reefton to Dobson) unused, there is more than enough capacity for generation plant outside the Westpower region to increase output to meet any increase in

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[242] Westpower's application to the Commerce Commission in relation to the Amethyst hydro proposal, August 2006 , at para 21. See also Westpower's 2015 – 2017 Statement of Corporate Intent, which states that, in generation, its strategic objective is "to continue to support existing West Coast electricity generation schemes and to support proposed distributed generation through our network connection policies."

[243] This dominant focus on increasing self sufficiency is evident in many parts of Westpower's Waitaha application. For example, see Appendix 21, sections 7.4 and 7.5

[244] Transpower's 2014 Annual Planning Report, section 3.2

[245] 2009 Review, Volume 1 at para 83

[246] The new converter equipment, known as Pole 3, replaces the Pole 1 equipment at both substations with state-of-the-art thyristor valve units. The HVDC Pole 3 project, worth up to $672 million, was commissioned over the 2013 year (Pole 3 by 30 May) – source: Transpower - https://www.transpower.co.nz/projects/hvdc-inter-island-link-project#zoom=7&lat=-41.1513&lon=174.982&layers=BT

demand within the Westpower region. In short, the total system of grid-connected generation in New Zealand is available to meet any increase on demand on Westpower's network.

As explained in section 7 and 8 of this report, existing generation in the New Zealand has more than sufficient capacity to meet demand growth in Westpower's region. As stated in the 2014 report of the Security and Reliability Council:

> "Assessed against the security standards set by the Electricity Authority, the New Zealand electricity system is currently oversupplied in generation following recent generation investment. This was likely in part due to recent low demand growth".[247]

As noted earlier, national demand still lies below 2010/11 levels and furthermore supply has increased significantly with new geothermals (such as Ngatamariki and Te Mihi) commissioned since then.[248]

In addition, as explained in section 9 of this report, a range of low cost new generation options are ready to go when demand growth increases to a level that would make them economic.

Further, as has been noted in section 10.6 of this report, well into the future, at a time when existing supply capacity feeding Westpower's network is becoming insufficient to meet demand, additional capacity can be provided at a relatively low cost by upgrading capacitor banks and the like at grid exit points to enable greater capacity to be delivered on the Dobson transmission lines.

"Self sufficiency" may have some parochial appeal, but it is not rational, and it is certainly not a sufficient reason to authorise an activity in a conservation area that would impose adverse effects.

In addition, the "self sufficiency" argument is probably not relevant under Part 3B of the Conservation Act 1987. In section 17U(4)(a), it is clear that if the activity could reasonably be undertaken in another location, the Minister must decline the application. The alternative location does not have to be in the applicant's region. Nor does it have to be undertaken by the applicant. Therefore whether the activity in the alternative location would promote "self sufficiency" in the Westpower region is not a relevant consideration under Part 3B.

The interests of electricity consumers on the West Coast would be best served by delivering electricity at the lowest cost over time while meeting their reasonable needs for security of supply. That means supplying electricity from the lowest cost sources, taking into account the cost and reliability of delivery. Some embedded generation may meet this threshold, but it does not follow as a rule that embedded generation is best – contrary to Westpower's view

[247] Security and Reliability Council, "The system operator's annual assessment of security of supply", 28 May 2014, at bottom of page 6

[248] FNZC

that distributed generation is "the most effective and secure way of meeting growing demand for electricity in the South Island".[249]

In summary, Westpower's assertions in relation to "self sufficiency" do not provide sufficient reason to conclude that it would be appropriate under Part 3B of the Act to authorise an activity in a conservation area that would impose adverse effects.

12.7 Community ownership

12.7.1 Westpower's view

At page 3 of Appendix 22 its Waitaha application, Westpower asserts:

> "Westpower differs from these companies in that it has a focus on providing and managing generation and supply for the benefit of the local community. Westpower has a particular interest in ensuring security of supply for its consumers within its distribution area. The schemes referred to above have been proposed by companies that are not West Coast owned and therefore the returns do not remain on the Coast. Apart from the Amethyst Hydro Scheme, all other power generation Schemes within the Westpower distribution area are owned either by TrustPower or NZ Energy, both of which are private companies".
>
> "These companies, by their nature, have a more national focus and there are a number of reasons why other companies will have chosen to withdraw or put their plans for larger Schemes on hold. Westpower differs from these companies in that it has a focus on providing and managing generation and supply for the benefit of the local community".
>
> "Whilst the company is run on a commercial basis, as would be anticipated by the community, the revenue is put back into the assets owned and managed on behalf of the community or returned from time to time to consumers in the form of rebates".
>
> "In the early 1990's the government required the community to divest itself of generation assets which then came under the control of national generators. This essentially disabled the ability for the local community to provide for itself, and plan for the future, in a self-sufficient manner. Westpower's return to hydro-development is part of reinvigorating the generating capabilities of the West Coast community, both current and future generations, and is aimed at regaining a level of local self-sufficiency in generation and supply based on a local and renewable hydro resource". *[Baldwin note - It was 1998/99, not "the early 1990s]*

[249] Westpower's application to the Commerce Commission in relation to the Amethyst hydro proposal, August 2006 , at para 21. See also Westpower's 2015 – 2017 Statement of Corporate Intent, which states that, in generation, its strategic objective is "to continue to support existing West Coast electricity generation schemes and to support proposed distributed generation through our network connection policies"

12.7.2 Comment and rebuttal

Once again, Westpower's reasoning is 'political' in nature. Westpower may have disagreed strongly with the forced sale of its generation and retail assets in 1998/99 and it may wish to re-build its generation asset base. However, this is not a sufficient reason to authorise adverse effects in a conservation area, particularly when the project is not required to meet the community's electricity needs and is not likely to be financially viable in the reasonably foreseeable future.

Westpower's view that alternative schemes are "not West Coast owned and therefore the returns do not remain on the Coast" is another 'political' argument, which is not relevant under Part 3B of the Conservation Act 1987. Section 17U(4)(a) is clear: if the activity could reasonably be undertaken in another location, the Minister must decline the application. The activity in the alternative location does not have to be undertaken by the applicant. Whether any returns from the activity in the alternative location would remain in the Westpower region is not relevant under the Act.

Westpower's assertions in relation to community ownership are not supported by any evidence and do not provide sufficient reason to conclude that it would be appropriate under Part 3B of the Act to authorise an activity in a conservation area that would impose adverse effects.

12.8 Security of supply

12.8.1 Westpower's view

Westpower asserts at page 7 of its application:

> "The local generation Westpower is developing is able to assist during transmission outages. This is particularly important in the event of the short term loss of all transmission into the region...In the absence of power from the national grid, the Waitaha and Amethyst Hydro Schemes can provide sufficient power to enable these smaller stations e.g. the Arnold to restart and minimise the disruption of supply to the community. This is a definite advantage in improving security of supply within the Coast."

Also at page 120 of its application:

> "The Scheme will provide some protection against situations when no or restricted external transmission capacity into the region is available. For residential consumers, outages as a result of transmission failures are likely to be sufficiently brief to cause only minor inconvenience. However for business customers with high electricity reliance or consumption the costs can be more significant – either in terms of lost production or the requirement to invest in expensive back-up sources of electricity supply."

12.8.2 Comment and rebuttal

Since the transmission upgrade in 2011 (described in section 6.7 of this report), reliability of supply into Westpower's network has improved significantly

In short, transmission reliability into Westpower is good. As Transpower notes in its 2014 Annual Planning Report (section 16.9, page 251):

> "The customers (Westpower, Buller Networks, Network Tasman, and Orion) have not requested a higher security level and there are no plans to increase bus security."

As Westpower notes in its 2014 Asset Management Plan (section 1.8, page 14);

> "A second 110 kV transmission line from Reefton to Dobson and its associated equipment was commissioned in late 2011, significantly improving the security of supply in the area."

This is shown in the reliability charts below – **note in particular, the low level of interruption to transmission from 2011.**

Figure 62: Unplanned supply interruptions by GXP - Westpower.
Source: Transpower

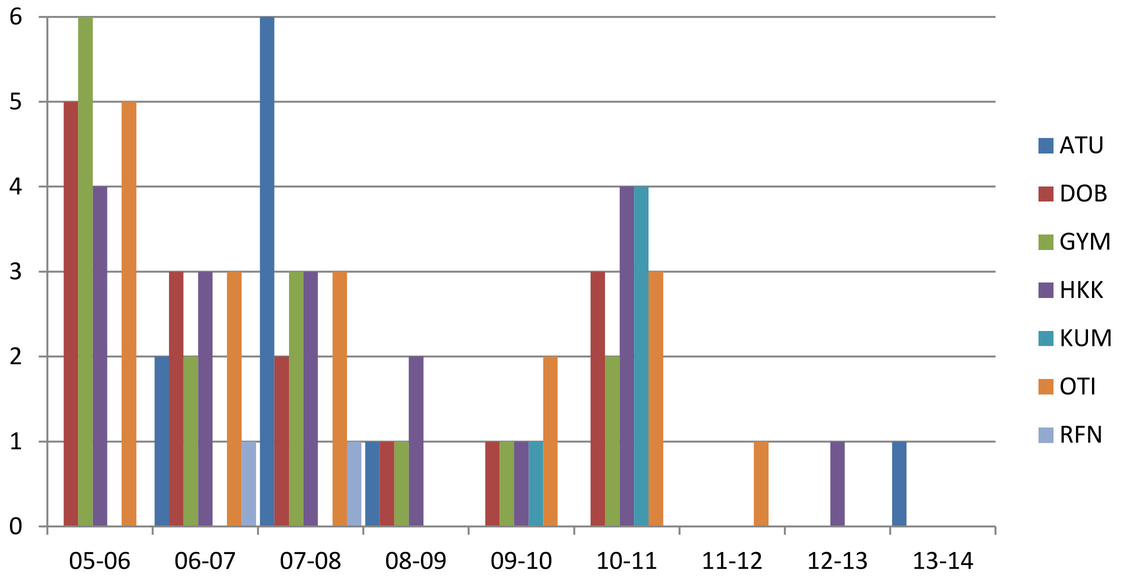


Figure 63: Number of transmission interruption events – Westpower.
Source: Transpower

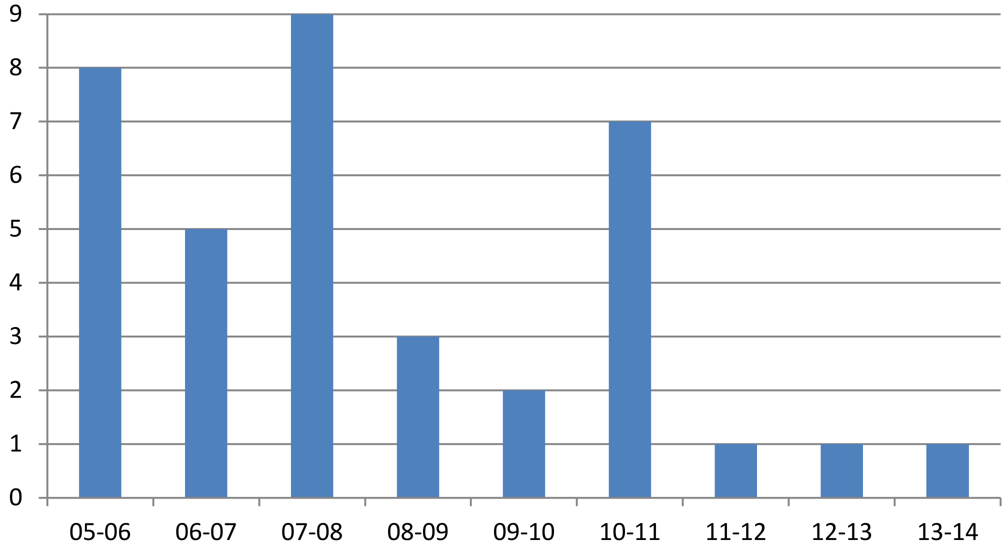
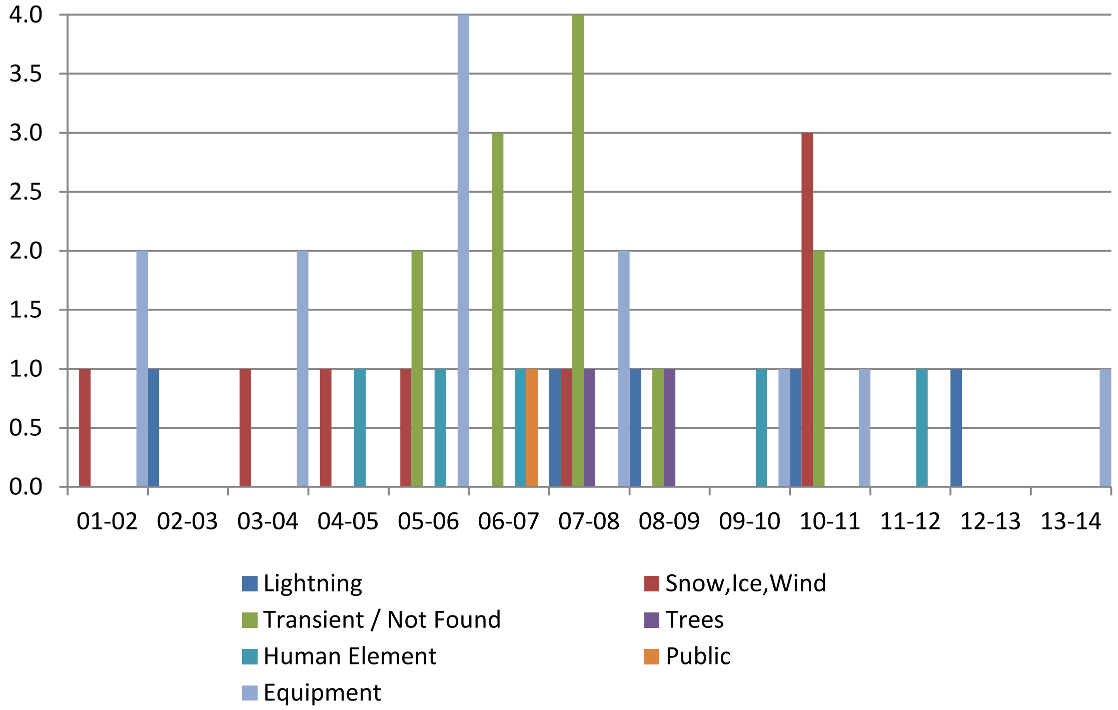


Figure 64: Transmission interruption events by type - Westpower.
Source: Transpower



In its 2014 Asset Management Plan, Westpower acknowledges the 2011 transmission upgrade delivered security of supply:

> "The DOB-TEE A line effectively doubles the transmission capacity, **thus providing security to the West Coast.**"[250] [Emphasis added]

Westpower states further:

> "The southern part of the Westpower network is fed from a double-circuit 66 kV line from Coleridge, which is supported by a limited capacity 66 kV connection between Dobson and Kumara (see Figure 3.3). **This provides an acceptable level of supply security,** although some load curtailment may be necessary should a common mode fault affect both circuits of the incoming double-circuit line at the same time. **The probability of such a fault occurring is relatively low**."[251] [Emphasis added]

Westpower's assertions in relation to security and reliability of supply are not supported by the evidence and do not provide sufficient reason to conclude that it would be appropriate under Part 3B of the Act to authorise an activity in a conservation area that would impose adverse effects.

12.9 Transmission losses

12.9.1 Westpower's view

Westpower asserts at page 8 of Westpower's application:

> "The current electricity supply relies on the importation of electricity over long distance transmission lines. Transmission losses approaching up to 20% occur as a result of power being imported from outside the West Coast. This results in costs to the wider community in terms of energy loss as well as to the local West Coast community in terms of financial costs."

12.9.2 Comment and rebuttal

Westpower's transmission losses are outlined in section 3.10 of this report. On average, around 8.5% to 13% of electricity is lost in transporting electricity to Westpower's network using Benmore as the reference point.

The days of average annual transmission losses of 20% are from a different era. In the four years 2011 to 2014, average annual transmission losses have not exceeded 13.6%.

In 2005, the average location factor at Dobson was 1.215 – that is to say, 21.5% of electricity was lost between Benmore and Dobson[252]. In 2014, it was reduced to 1.124 – or 12.4% losses – an improvement of 9.1% percentage points. Much of this improvement is due to Transpower's upgrade completed in 2011 of the transmission line between Reefton and Dobson.

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[250] Westpower's Asset Management Plan 2014-2024, section 5.4.2, pages 136 and 137

[251] Westpower's Asset Management Plan 2014-2024, section 3.2, page 66

[252] Assuming no constraints

Transmission losses into Westpower's network have been greatly exaggerated over the years and become key plank in the case for Westpower becoming "self sufficient" in electricity generation. For example, in 2009 West Coast Regional Council chief executive, Chris Ingle, asserted:

> "We don't want to rely on the Waitaki scheme and lose **50 per cent** of the energy on the way over".[253] [Emphasis added]

This 50% figure is not correct. As noted above, the average for 2011 to 2014 was 8.5% to 13%.

Westpower's assertions in relation to transmission losses are not supported by the evidence and do not provide sufficient reason to conclude that it would be appropriate under Part 3B of the Act to authorise an activity in a conservation area that would impose adverse effects.

12.10 Confidence to investors in the West Coast

12.10.1 Westpower's view

Westpower asserts at page 8 of Westpower's application:

> "The longer term and perhaps less obvious direct benefits from investing in local power generation come from improving economic confidence and the resulting development and infrastructure that may result from this. The Scheme would enhance security of supply in the West Coast region, in turn providing potential investors and developers with the confidence to invest in the West Coast region, assured that their energy demands can be met in both the medium and long term... The long term benefits of reduced transmission losses and security of supply underpin these economic benefits."

12.10.2 Comment and rebuttal

Here again Westpower's reasoning is 'political' in nature. It is also specious.

There is no evidence that confidence to invest in the West Coast region would be lower without the Waitaha scheme, or indeed that it would be higher with the scheme.

On the contrary, Westpower acknowledges in its 2014 Asset Management Plan,:

> "Currently, there is sufficient n-1 transmission capacity available in the transmission network feeding the West Coast, to ensure that major new loads can be supplied on an uninterruptible basis, and so **electricity supply should not be a constraint** to **future economic development**". [Emphasis added]

[253] The Press, 17 July 2009 - http://www.stuff.co.nz/the-press/news/2601161/Council-thinks-big-on-hydro-power-projects

As outlined in section 10, there is a very large surplus of electricity supply capacity into Westpower's network which will take many years to use up, and transmission reliability since 2011 has been at a good level.

Westpower's assertions in relation to investment confidence are not supported by any evidence and do not provide sufficient reason to conclude that it would be appropriate under Part 3B of the Act to authorise an activity in a conservation area that would impose adverse effects.

12.11 Reduce carbon emissions

12.11.1 Westpower's view

Westpower asserts at page 8 of its application to the Minister of Conservation:

> "...there will be a role for new renewable energy sources like the Scheme in meeting electricity demand, even if demand growth is slow. New renewable sources of supply will be required to replace retired thermal capacity"

Westpower also assert at page 9 in its application to the Minister of Conservation that:

> "increasing self-sufficiency on the West Coast will contribute in replacing non-renewable energy (e.g. thermal generation) elsewhere..."

Referring to the Government's economy-wide target for reducing carbon emissions, Westpower states at page 120 of its application to the Minister of Conservation that:

> "If the Scheme results in the avoidance of an equivalent level of generation from gas thermal plants there will be an estimated reduction of 51,120 tonnes of carbon dioxide equivalent greenhouse gases and...this implies an annual saving of $1.3 million in terms of reduced emission units...The equivalent annual saving if coal thermal generation is displaced is estimated at $1.9 million"

12.11.2 Comment and rebuttal

It is not at all clear that the Waitaha would reduce carbon emissions from electricity generation in the New Zealand system as claimed be Westpower.

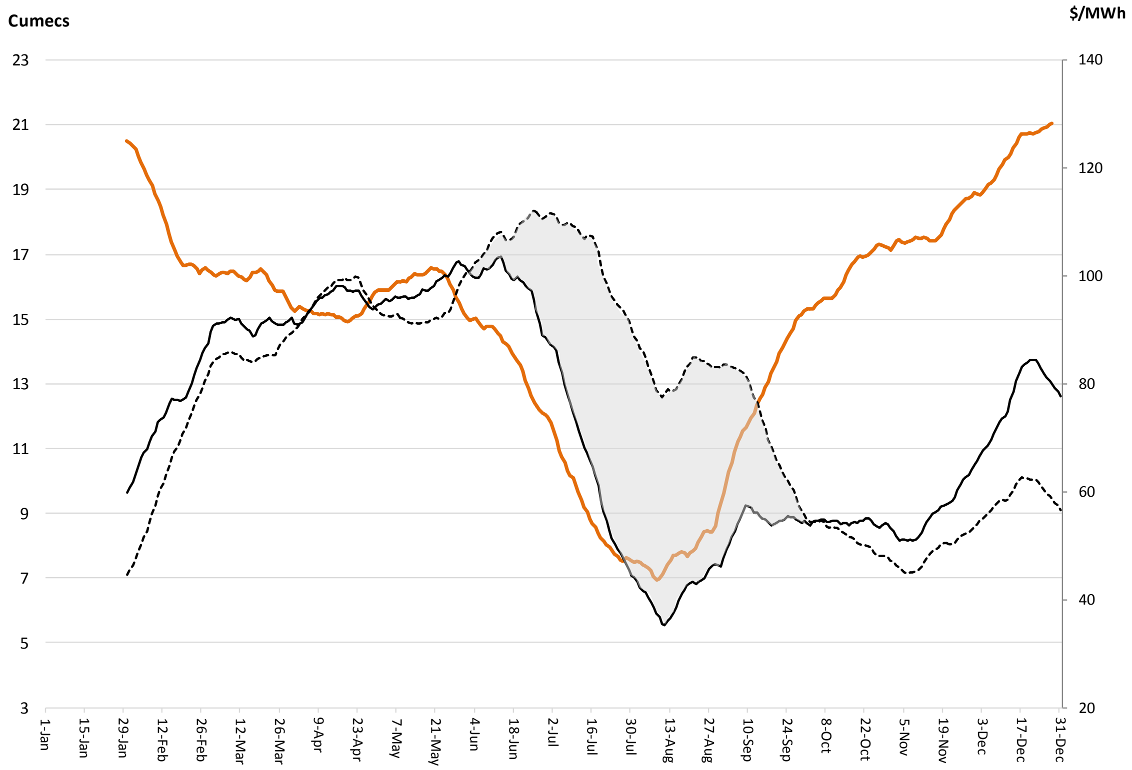
There may be periods when output from the Waitaha scheme would mean that more hydro power from the South Island is sent to the North Island than would otherwise have occurred, resulting in less generation from the thermal stations in the North Island.

However, in a normal year, thermal generation in New Zealand tends to be greatest between mid-March and mid-September. As set out section 11.6 of this report, this is the period when the Waitaha scheme would, on average, have its lowest 'take' flows. In other words, during the normal period of peak thermal production in a year, the Waitaha would not be well placed to displace thermal generation. This is shown in the chart below (which is also in section 11.6 of this report).

Figure 65: Waitaha generation-weighted prices relative to prices at Hokitika node and 'take' volumes – 2006 to 2012

Source: Author using Electricity Authority and Westpower data – 25/3/06 to 18/4/12.

Explanation: The dotted black line is the 30 day moving average of prices at HKK0661 (use right hand axis). The solid black line is the 30 day moving average of generation-weighted prices (use right hand axis). The orange line is the 30 day moving average of 'take' volumes for generation (use left hand axis)



Westpower's claim that "increasing self-sufficiency on the West Coast will contribute in replacing non-renewable energy (e.g. thermal generation) elsewhere…" is also questionable. As outlined in section 9 of this report, MBIE's 2015 Draft Electricity Demand and Generation Scenarios concludes that:[254]

- There is likely to be significant investment in geothermal plants over the next 30 years.[255] At current costs, geothermal plant is relatively cheaper than other technologies.

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[254] "Draft Electricity Demand and Generation Scenarios: Consultation Guide — 2 April 2015", MBIE, at paras 200 – 228

[255] This is consistent with the MBIE's view in 2013, which was that even if new coal and gas generation options are excluded, new generation supply is expected to continue to come from new geothermal plants over the next 30 years "New Zealand's Energy Outlook: Electricity Insight", July 2013, MBIE, at page 8 - http://www.med.govt.nz/sectors-industries/energy/energy-modelling/modelling/new-zealands-energy-outlook-electricity-insight

- The next cheapest new power stations are Tauhara stage 2 (geothermal) with 250 MW, Hawea control gates (hydro) with 17 MW, Hauauru ma raki stage1 (wind) with 252 MW, and then Pukaki canal (hydro) with 35 MW – all at or under $90/MWh, which is less expensive that the estimated unit cost of electricity from the Waitaha scheme.

In other words, the Waitaha scheme would not be replacing thermal generation; it is more likely to displace lower cost new renewable generation. To the extent that carbon emissions are reduced, it is best achieved by renewable generation that is lower cost than the proposed Waitaha scheme.

Westpower's assertions in relation to the Waitaha scheme reducing carbon emissions are not supported by the evidence and do not provide sufficient reason to conclude that it would be appropriate under Part 3B of the Act to authorise an activity in a conservation area that would impose adverse effects.

12.12 Conclusion in relation to Westpower's reasons

As noted above, section 17S(2) requires a applicant to supply, in addition to the contents required by section 17S(1):

> "**reasons for the request** and sufficient information to satisfy the Minister, in terms of section 17U, that it is both **appropriate** to grant a lease, *profit à prendre*, licence, or easement and lawful to grant it" [emphasis added]

As outlined above, Westpower's reasons for the proposed Waitaha scheme are not supported by the evidence or are not relevant under Part 3B of the Act. Individually or together, Westpower's reasons do not therefore provide sufficient reason to conclude that it would be appropriate under Part 3B of the Act to authorise an activity in a conservation area that would impose adverse effects.

13. Alternative locations for activity

13.1 Outline of this section

This section 13 is divided into the following parts, which are hyperlinked:

- Summary of key points
- Legal requirements on scope of alternatives
- Application not complete
- Range of alternatives
  - Additional electricity supply from existing generation
  - Alternative new hydro generation – Lake Hawea and Lake Pukaki canal
  - Other new generation schemes in New Zealand
  - Arnold scheme
  - Stockton mine and Stockton plateau
- Conclusion in relation to alternative locations

13.2 Summary of key points

The key points in this section 13 are as follows:

- From a legal perspective, Westpower's Waitaha application is therefore not complete in that it does not address alternatives on the terms required by section 17U(4)(a)

- There is a wide range of alternative locations within the relevant time-frame at which the activity in question could be reasonably undertaken outside the relevant conservation area.

13.3 Legal requirements on scope of alternatives

13.3.1 Prohibition on granting concession

As set out in section 2 of this report, the Minister is not allowed to grant a concession under Part 3B of the Act if he or she is satisfied the activity could reasonably be undertaken in another location that is outside the conservation area to which the application relates; or in another conservation area or in another part of the conservation area to which the application relates, where the potential adverse effects would be significantly less. This is set out in section 17U(4)(a) of the Act.

13.3.2 "Activity"

As outlined in section 2.4 of this report, the overall "activity" in question is "the business of generating electricity", which under section 17O is not permitted in a conservation area unless authorised by a concession.

13.3.3 "Activity" at alternative location may be undertaken by another party

In the context of Part 3B of the Act, it is important to note that "activity" is distinct from the party carrying out the activity. This is clear from section 17S(1)(f), which requires:

> "relevant information relating to the applicant, including any information relevant to the applicant's ability to carry out the proposed activity."

Under section 17U(4)(a), the question is whether the "activity could reasonably be undertaken in another location." It does not have to be undertaken by the applicant. The range of alternatives to be considered under section 17U(4)(a) includes any other party carrying out the "activity" in question, which is "the business of generating electricity."

Even if the activity were defined as "the business of electricity generation that will contribute to meeting future electricity demand in Westpower's region", the range of alternative locations to be considered for the purposes of section 17U(4)(a) is still wide.

13.3.4 Alternatives not limited to Westpower or embedded locations

The alternatives to be considered are not at law required to be limited to only generation options undertaken by Westpower, or only options that would be embedded within Westpower's network. The "activity" under Part 3B is not "generation that increases Westpower's 'self sufficiency' in electricity".

Nor are the alternative locations limited to the West Coast. Unlike the decision-making authority in the consent process under the Resource Management Act 1991, the Minister's jurisdiction is not limited to a regional territorial boundary. Nor does the Part 3B of the Conservation Act 1987 imply any such restriction.

13.3.5 Time-frame for alternatives

Given that, for the reasonably foreseeable future, the Waitaha scheme is neither needed nor financially viable, the alternatives to be considered for the purposes of section 17U(4)(a) should include electricity generation options that may become financially viable within the same timeframe as the Waitaha scheme may become needed and viable.

13.4. Application not complete

Westpower's Waitaha application indicates that in 2005 it commissioned a scoping study of six rivers within is general network area: the Waitaha, Kakapotahi, Toaroha, Amethyst River, Rough River and Big River. This was reduced to two: the Waitaha and Kakapotahi (Little Waitaha) Rivers; and then to one – the Waitaha.

Westpower's evaluation criteria were predicated on a hydro scheme of some size with a tunnel diversion on a river close to its network area with significant water flows,[256] which limited the range of alternatives considered. It is also not clear how many of the 50 'mini' or 'small' scale projects (with a combined capacity of approximately 300 MW) identified by Sinclair Knight Merz[257] were explored by Westpower. Some of those options may have less adverse impacts on conservation values than the Waitaha proposal. This conclusion has not been ruled out.

In relation to alternative locations for the activity of electricity generation, Westpower's application focuses on second-order choices of scope and layout for the proposed scheme within the between Kiwi Flats and the lower valley of the Waitaha River. Westpower's "alternatives" are more variations on the proposed Waitaha scheme, rather than the full range of alternative locations for the activity.

From a legal perspective, Westpower's Waitaha application is therefore not complete in that it does not address alternatives on the terms required by section 17U(4)(a), as outlined above.

13.5 Range of alternatives

Alternatives to the Waitaha scheme include (in no particular order) the:

- Additional generation from existing generation stations
- Lake Hawea control gates scheme
- Lake Pukaki canal option;
- Any of the other new generation schemes in New Zealand already consented;
- Arnold hydro scheme; and
- Stockton mine and Stockton plateau hydro schemes.

Each of these is outlined briefly below.

13.5.1 Additional electricity supply from existing generation

As noted sections 10.5 and 10.6 of this report, with about 50% of a main transmission line feeding Westpower (Reefton to Dobson) unused, there is more than enough capacity for generation plant outside the Westpower region to increase output to meet any increase in demand within the Westpower region. In short, the total system of grid-connected generation in New Zealand is available to meet any increase on demand on Westpower's network.

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[256] Westpower's Waitaha application, Appendix 22 at section 6

[257] "Renewable Energy Assessment – West Coast Region", Sinclair Knight Merz (SKM), 4 August 2008. SKM summarised the hydropower potential identified by Works (1990) and Ministry of Economic Development (1982). NIWA has categorised the resource locations based on underlying capital cost assumptions broadly based on the Statement of Opportunity reports prepared on behalf of the Electricity Commission along with support from various reports. These locations filtered further by NIWA excluding sites inside National Parks and Wilderness Areas. The indicative hydro generation potential sites **excluding** sites inside National Parks and Wilderness areas are in Table 15 and Figure 18– a high-resolution map is in Appendix G – page 59.

As outlined in section 7 and 8 of this report, existing generation in New Zealand has more than sufficient capacity to meet load growth demand growth in Westpower's region (keeping in mind that, as set out in section 10.6 of this report, existing capacity supplying Westpower's network is more than sufficient to meet even Westpower's overly optimistic forecast).

13.5.2 Alternative new hydro generation – Lake Hawea and Lake Pukaki canal

The next cheapest new hydro projects in New Zealand are the Hawea control gates scheme (17 MW) and the Pukaki canal scheme (35 MW), both with a unit cost ('project LRMC') estimated at under $90/MWh in MBIE's draft 2015 LRMC rankings.

As outlined in section 7.7 of this report, both have been fully consented and both were put on around 2012 until the electricity supply and demand situation makes it economic for them to be built. As MBIE noted in its publication "Energy in New Zealand 2013" at page 65:

> "...construction of new generation is expected to be halted until it is economically viable to build. The Waitaki River Hydro Scheme is an example of this, with the project put on hold until new generation is needed."

As noted in section 9 of this report, Hawea is ranked 3rd and Pukaki canal is ranked 6th in MBIE's draft 2015 rankings (which are set out again for convenience below).

Both projects are outside the conservation area that the Waitaha scheme would use. In terms of section 17U(4)(a) of the Act, therefore, the activity could reasonably be undertaken in another location that is outside the conservation area to which the application relates.

13.5.3 Other new generation schemes in New Zealand

As outlined in sections 8 and 9 of this report, there is a very large quantity of new generation projects, fully consented, that are waiting for medium to longer term electricity supply and demand conditions to make new generation economic. In April 2015, MBIE advised[258] that there is over 4700 MW of generation that has been consented. The majority of consented generation is wind (over 3000 MW). There is an additional 714 MW of consented renewable generation, including 263 MW of geothermal. There is also 980 MW of consented gas.

Some of those new projects are referred to in MBIE's 2015 rankings below based on 'project LRMC' or 'unit cost'. All of these projects are outside the conservation area that would be used by the Waitaha scheme.

[258] "Draft Electricity Demand and Generation Scenarios Consultation Guide — 2 April 2015", MBIE, para 64, page 20

Type	Project	Fully consented	MW	Typical GWh pa	Capital cost $m	Variable O&M, $/MWh	Fixed O&M, $/kW	LRMC $/MWh
Geothermal	Tauhara stage 2	Yes	250	1971	1201	0.00	105.00	79.06
Gas - CCGT	Otahuhu C	Yes	400	2803	610	4.30	35.00	83.04
Hydro	Hawea Control Gates	Yes	17	74	53	0.86	6.38	87.49
Wind	Hauauru ma raki stage1	Yes	252	975	627	3.00	50.00	89.43
Wind	Hauauru ma raki stage2	Yes	252	975	627	3.00	50.00	89.43
Hydro	Lake Pukaki	Yes	35	153	114	0.86	6.38	90.45
Gas - CCGT	Rodney CCGT stage 1	Yes	240	1682	384	4.30	35.00	91.27
Gas - CCGT	Rodney CCGT stage 2	Yes	240	1682	384	4.30	35.00	91.27
Wind	Turitea	Yes	183	708	478	3.00	50.00	94.91
CCGT	PropopsedCCGT1	Proposed	194	1360	333	4.30	35.00	95.01
Wind	Hawkes Bay windfarm	Yes	225	780	560	3.00	50.00	96.68
Geo	Tikitere LakeRotoiti	Applied	45	355	303	0.00	105.00	97.53
Wind	Project CentralWind	Yes	120	416	314	3.00	60.00	99.05
Hydro	Arnold	Yes	46	201	192	0.85	6.38	99.51
Hydro	Lake Coleridge 2	Applied	70	307	289	0.85	6.38	102.36
Hydro run of river	Stockton Mine	Yes	35	153	135	0.80	6.38	103.24
Wind	Waitahora	Yes	156	541	408	3.00	50.00	105.54
Wind	Puketoi	Applied	159	551	416	3.00	50.00	105.55
Wind	CastleHill stage1	Yes	200	693	513	3.00	50.00	105.97
Wind	CastleHill stage2	Yes	200	693	513	3.00	50.00	105.98
Wind	CastleHill stage3	Yes	200	693	513	3.00	50.00	106.00
Geothermal	Rotoma LakeRotoma	Applied	35	276	260	0.00	105.00	106.23
Geothermal	Kawerau TeAhiOMaui	Applied	10	79	76	0.00	105.00	107.81
Wind	Taharoa	Yes	54	209	166	3.00	60.00	109.15
Hydro (SC)	North Bank Tunnel	Applied	260	1139	1045	0.84	6.38	109.21
Hydro run of river	Stockton Plateau	Yes	25	110	106	0.86	6.38	111.78
Hydro run of river	Wairau	Yes	70	307	297	0.70	6.38	112.12

It is widely accepted in the market that the next cheapest new power stations are Tauhara stage 2 (geothermal) with 250 MW.

As noted in sections 10.5 and 10.6 of this report, with about 50% of a main transmission line feeding Westpower (Reefton to Dobson) unused, there is more than enough capacity for generation plant outside the Westpower region to meet any increase in demand within the Westpower region.

As also noted earlier, a major upgrade of inter-island electricity transmission connection (the HVDC) completed in 2013 means that there are no material technical barriers in transporting power generated in the North Island to the South Island (and vice versa).[259]

[259] The new converter equipment, known as Pole 3, replaces the Pole 1 equipment at both substations with state-of-the-art thyristor valve units. The HVDC Pole 3 project, worth up to $672 million, was commissioned over the 2013 year (Pole 3 by 30 May) – source: Transpower - https://www.transpower.co.nz/projects/hvdc-inter-island-link-project#zoom=7&lat=-41.1513&lon=174.982&layers=BT

All of the new generation projects referred to above are outside the conservation area that the Waitaha scheme would use. In terms of section 17U(4)(a) of the Act, therefore, the activity could reasonably be undertaken in another location that is outside the conservation area to which the application relates.

13.5.4 Arnold scheme

Section 6.7 of this report refers to some of the new generation proposals for the West Coast region consented between 2008 and 2012. Three are on hold, but have the potential to be re-activated if and when supply and demand conditions, and expected wholesale electricity prices, were to make new generation financially viable.

Trustpower's hydro scheme on the Arnold River 46 MW (220 GWh per year) has been fully developed in its consents, plans, design and costing. While it was put on hold in 2012, Trustpower advised: "It doesn't mean we're not going to do it...Right now it's just not financially viable.'' It remains a strong alternative if and when wholesale prices and energy demand rise to make new generation viable[260].

As set out in section 10.5 of this report, Westpower has already factored Trustpower's new Arnold scheme into its asset management plans:

> "If and when the TrustPower proceeds with its proposed 40 MW Arnold power station, a new 66 or 110 kV substation may be required at Kokiri to connect the power station into the local transmission grid. The new substation may be required by 2018/19, depending on a final decision to proceed from TrustPower"[261].

This project is outside the conservation area that the Waitaha scheme would use. In terms of section 17U(4)(a) of the Act, therefore, the activity could reasonably be undertaken in another location that is outside the conservation area to which the application relates.

13.5.5 Stockton mine and Stockton plateau

There are two consented hydro schemes related to the Stockton open-cast coal mine: Hydro Developments'[262] scheme, which is 25 to 54 MW, 230 GWh per year[263]; and Solid Energy's scheme, which is 35 MW, 195 GWh per year. The two parties agreed in October 2010 that Hydro Developments would have 'first call' on the water, access to the site to complete its

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[260] http://www.odt.co.nz/regions/west-coast/209347/west-coast-hydro-scheme-shelved

[261] Westpower's Asset Management Plan 2014-2024, section 5.7.2 at page 148

[262] Succeeded by Hydro Developments (2013) Limited following litigation by one shareholder against the other – Coll v Hydro Developments Limited (High Court) CIV 2012-409-000879, 31 May 2012

[263] "When fully commissioned the scheme will provide on average 229Gwhrpa with installed generation in the order of

54MW. 40-45 GWh pa is expected to come on stream in 2014 from 12MW installed at Weka power station" - Statement of Evidence of John M Easter for the Director General of Conservation dated 15 May 2012 at para 9 – www.doc.govt.nz/.../026-john-easther-mokihinui-final%20evidence.pdf investigations, and a clear run to progress its scheme provided it did so in a timely manner [264].

Hydro Developments' scheme would divert and dam waste water (acid mine drainage) from the mine, and flow it through tunnels and into two underground power stations. As Solid Energy observed in May 2012:

> "The environmental impact of this hydro scheme is extremely low in comparison to other generation options. It doesn't involve damming large rivers, it sits alongside existing mine infrastructure and would actually support the mine's programme by further improving the quality of water leaving the site"[265].

Hydro Developments added in June 2012:

> "Relatively small quantities of water from elevated tributaries on the highly modified Stockton Plateau are captured and discharged directly to the sea via a submarine outfall. This leaves the downstream rivers wild and scenic values largely unaffected"[266]

In short, the Stockton scheme is designed to have only minor effects on the environment.

In May 2012, John Easther for the Director General of Conservation stated in evidence that "HDL's analysis is that...the economic indicators for HDL's scheme are well within the current ranges required for investment in hydro infrastructure".[267]

Since then, the full extent of the electricity supply surplus has become apparent, West Coast electricity demand has declined, and wholesale electricity prices have flattened. In addition, Solid Energy is undertaking a major restructuring of its business as a whole in response to some serious financial and strategic challenges.[268]

Hydro Developments has advised that, in the last six months, it has worked with Solid Energy to modify the scheme's design to combine the best (most cost-effective) features of the two competing proposals. The result is a scheme with lower capital cost and optimised environmental outcomes. It would have two dams, a shorter tunnel, canals, surface penstocks, and a 25 to 45 MW power station, with discharge to the sea. The capital cost is

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[264] Statement of Evidence of John M Easter for the Director General of Conservation dated 15 May 2012 – at para 7 - www.doc.govt.nz/.../026-john-easther-mokihinui-final%20evidence.pdf. See also

http://www.scoop.co.nz/stories/BU1205/S00087/stockton-hydro-electricity-scheme-gains-consents.htm

[265] http://www.scoop.co.nz/stories/BU1205/S00087/stockton-hydro-electricity-scheme-gains-consents.htm

[266] http://www.stuff.co.nz/nelson-mail/7045182/Mohikinui-withdrawal-good-for-smart-hydro-scheme

[267] Statement of Evidence of John M Easter for the Director General of Conservation dated 15 May 2012 at para 8.6 - www.doc.govt.nz/.../026-john-easther-mokihinui-final%20evidence.pdf

[268] In relation to the Stockton coal mine, Solid Energy announced in June 2014 significant job cuts and a reduction in production. From Stockton's total workforce of 521, 102 mine staff and 35 management and administration jobs will go, plus a further 50 of the 120 jobs of contractors servicing the mine. Annual production will drop from 1.9 million tonnes to 1.4 million - http://www.odt.co.nz/news/business/305049/187-jobs-gone-stockton-coal-mine. See also Solid Energy's 2014 Annual Report at pages 9-11, and the 2013 Annual Report. Note also that the Stockton mine was impaired by $80m in Solid Energy's financial statements of 2012-13 in response to lower future coal price assumptions

estimated to be $65 to $120m, with the optimum size considered to be 35 MW at about $110m.

The Stockton hydro scheme could be embedded within the Buller Electricity's network and connected to the transmission grid. Under Hydro Developments' original proposal, the scheme would have been connected to the grid.[269]

The hydro scheme is intended to provide a solution to the mine's water quality risks and liabilities[270], while also delivering cost-competitive hydro generation.[271] Contaminated water from the mine would pass through sediment traps built into the dam design that would enable the water's eventual discharge into the sea to better meet water quality parameters in relevant resource consents.

The Stockton hydro scheme is predicated on Solid Energy contributing a significant proportion of the amount it currently allocates to manage its acid mine drainage and related environmental risks at the mine.[272] Hydro Developments considers the hydro scheme to be a significantly better[273] (lower cost and longer term) solution to the acid mine drainage problem than Solid Energy's current treatments.[274]

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[269] Statement of Evidence of John M Easter for the Director General of Conservation dated 15 May 2012 – at para 3.6 - www.doc.govt.nz/.../026-john-easther-mokihinui-final%20evidence.pdf

[270] Hydro Developments has noted that "the publicly stated net present value of the Crown's acid mine drainage (AMD) liability was reported in 2010 to be "in excess of $100 million for the year ended 30 June 2009" (Mark Pizey, SENZ National Environmental and Health and Safety Manager, para 3.1 evidence to the consent hearings for SENZ Stockton Hydro Project). SENZ's liability for mining activities is understood to be similar to the Crown's liability (for historic mining). Total liability is expected to exceed $200Million. Construction of HDL's scheme will discharge this liability" - Statement of Evidence of John M Easter for the Director General of Conservation dated 15 May 2012, at paras 8.1 and 8.2 - www.doc.govt.nz/.../026-john-easther-mokihinui-final%20evidence.pdf. Hydro Developments has advised that Solid Energy's AMD liability has recently been independent reviewed by a major accounting firm and the liability is reported to be substantial. For balance sheet purposes, Solid Energy's incentives are to use the lowest possible acceptable value.

[271] Statement of Evidence of John M Easter for the Director General of Conservation dated 15 May 2012 – at paras 8.4 and 8.2 - www.doc.govt.nz/.../026-john-easther-mokihinui-final%20evidence.pdf

[272] The nature of the water quality problem is described by the Parliamentary Commissioner for the Environment as follows: "The topography, in combination with the climate, the scale and the historic nature of Stockton mine mean that water run-off from the plateau has been affected by acid drainage for some time. When the amount of coal being extracted during the 1990s increased dramatically, it had an immediate and significant impact on the water quality in the streams flowing off the plateau into the Ngakawau River. The Ngakawau River became significantly contaminated and inhospitable to many species of aquatic life, including whitebait. Concern about the state of the river prompted local people to form a community action group named Ngakawau Riverwatch. Therefore, one of the major environmental management challenges for Solid Energy at Stockton mine has been improving the water quality in the streams flowing into the Ngakawau River. Management of this issue involves reducing acid mine drainage at its source, minimising sediment flowing into the streams from mine operations, and actively treating water flowing off the Stockton plateau". Source: "Stockton revisited: The mine and the regulatory minefield", Parliamentary Commissioner for the Environment, October 2009, section 4.2 at pages 28 – 29: www.pce.parliament.nz/assets/Uploads/Reports/pdf/Stockton_mine.pdf

[273] Statement of Evidence of John M Easter for the Director General of Conservation dated 15 May 2012, at paras 8.6 - www.doc.govt.nz/.../026-john-easther-mokihinui-final%20evidence.pdf

[274] Solid Energy's recent initiatives to mitigate the acid mine drainage problem are described in "Stockton revisited: The mine and the regulatory minefield", Parliamentary Commissioner for the Environment, October 2009, sections 4.3 and 4.6 at pages 28 – 33: www.pce.parliament.nz/assets/Uploads/Reports/pdf/Stockton_mine.pdf. Progress has been made, however Solid Energy appears to be still short of achieving relevant targets.

With Solid Energy contributing to the hydro scheme the value of its current water quality management budget, the full cost (or unit cost) of electricity from the proposed hydro scheme is considered by Hydro Developments to be significantly less expensive other new generation options. [275] On these assumptions, the project would appear to be attractive.

At this stage, Solid Energy is distracted by a range of strategic and financial challenges. However, the Stockton hydro scheme has the potential to be activated by a variety of events. A key factor will be how the environmental risks and liabilities relating to the mine are viewed over time by Solid Energy's creditors, environmental enforcement authorities, and the Crown.

In relation to enforcement of environmental conditions at the mine, the Parliamentary Commissioner for the Environment's observation in 2009 is likely to still apply: "Despite the progress in environmental management at Stockton, enforcement is still an outstanding issue for both councils [Buller District Council and West Coast Regional Council]".[276]

In summary, if (or rather when) a longer term, lower cost solution is required for Solid Energy's acid mine drainage problem, the Stockton hydro scheme has the potential to become financially viable. With Solid Energy strongly engaged, various electricity companies would likely become interested.

Given the medium to longer term surplus of electricity supply into Westpower's network[277], activation of the Stockton hydro option has the potential to occur within the relevant time-frame.

The Stockton hydro option is outside the conservation area that the Waitaha scheme would use. In terms of section 17U(4)(a) of the Act, therefore, the activity could reasonably be undertaken in another location that is outside the conservation area to which the application relates.

13.5.6 Transmission alternative

Well into the future, at a time when existing supply capacity feeding Westpower's network is becoming insufficient to meet demand, additional capacity can be provided at a relatively low cost by upgrading capacitor banks and the like at grid exit points to enable greater capacity to be delivered on the Dobson transmission lines.

[275] Hydro Developments considers that the cost of alternative new generation is about $800 - $1,000 per GWh, and that the full cost of electricity from the proposed Stockton scheme would be very significantly below that level. With Solid Energy contributing about $20m to address its water quality risks, the scheme would cost an additional approximately $65m to produce 180 GWh per year.

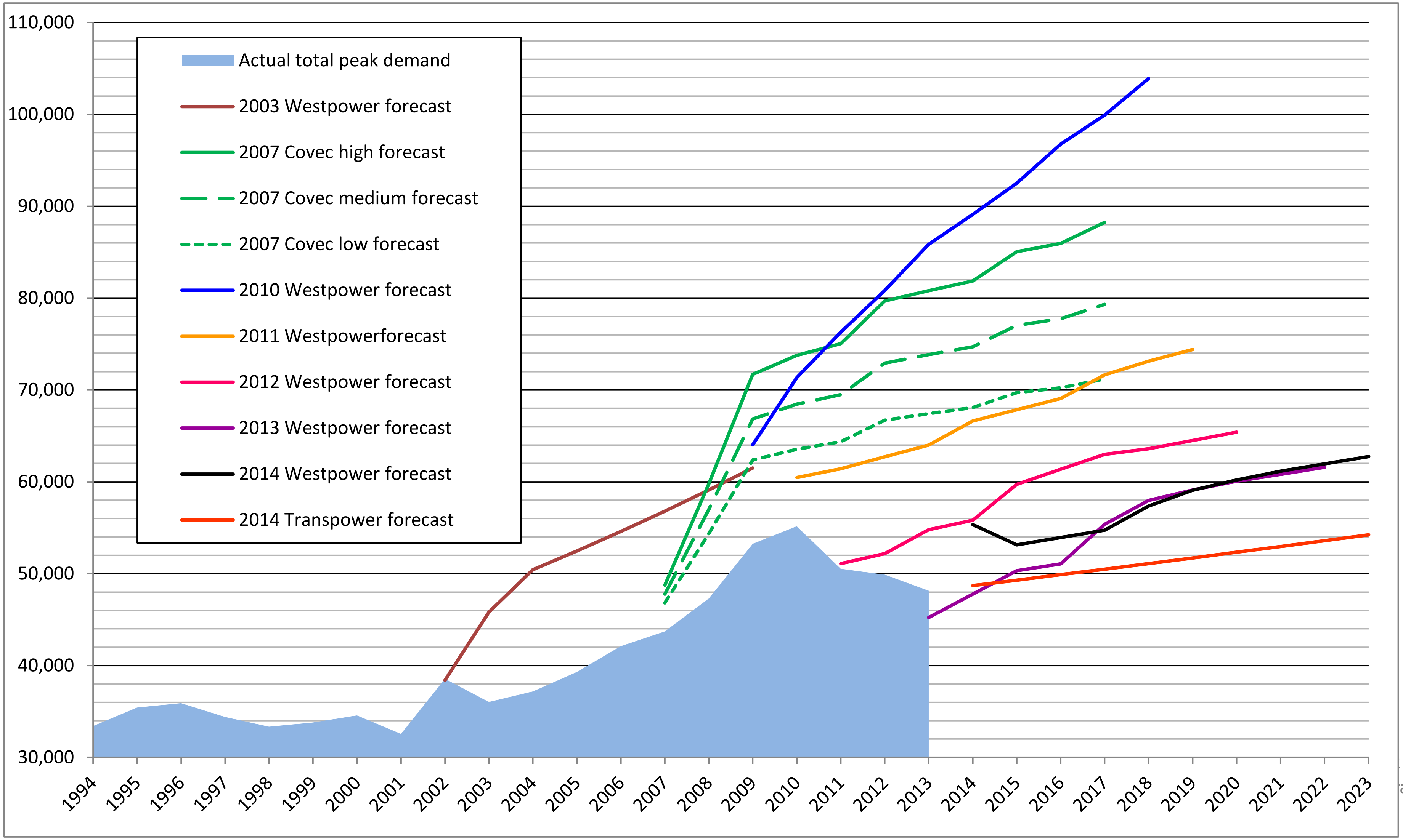
[276] "Stockton revisited: The mine and the regulatory minefield", Parliamentary Commissioner for the Environment, October 2009, section 3.4 at pages 25 – 26: www.pce.parliament.nz/assets/Uploads/Reports/pdf/Stockton_mine.pdf

[277] As outlined in section 10 of this report

13.6 Conclusion in relation to alternative locations

Based on this analysis, it is reasonable to conclude that there is a wide range of alternative locations within the relevant time-frame at which the activity in question could be reasonably undertaken outside the relevant conservation area. Under section 17U(4)(a) of the Act, the Minister is therefore not allowed to grant concessions for the activity proposed by Westpower in relation to the Waitaha scheme.

Appendix 1: Forecast demand relative to actual demand on Westpower's network



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