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Evaluation of potential electricity sector outcomes from revised minimum flow regimes on selected rivers

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Background

The Water Directorate (developed by the Ministry for the Environment together with the Ministry for Primary Industries and the Department of Conservation) is considering a range of possible policy options to improve New Zealand's freshwater management.

As part of the process of trying to determine which potential water management changes are likely to deliver greatest benefit to New Zealand, the Water Directorate is currently seeking to estimate the potential economic impact of the introduction of a national objectives framework (NOF), including national bottom-lines for water quality attributes, on existing and future users of freshwater across a range of different commercial sectors and non-commercial users.

One such sector is the electricity generation sector where freshwater from rivers and lakes is used to generate electricity directly through hydro power schemes, and indirectly through providing cooling capabilities for some thermal power schemes.

This report seeks to evaluate the potential economic impact of altered power generation outcomes arising from altered minimum flow regimes on various rivers which are used for electricity generation.

It is understood that there are no specific proposals relating to altered minimum flows for New Zealand's rivers, either on a national or individual river basis. The recent discussion document released by MfE "*Freshwater reform 2013 and beyond*" reaffirmed that regional councils will continue to make decisions about freshwater management at a catchment level.

Rather, the intent of this exercise is to highlight the potential nature and scale of economic impacts on electricity generation *if* some rivers were to have increased minimum flow requirements – in effect a change in available water *quantity*.

Concept understands that parallel studies are also underway considering the potential impact of national bottom lines for water *quality* attributes. With regards to the relationship between these two types of studies, MfE have advised that whilst this report examining the electricity sector will be useful information for officials to consider alongside the assessments of the impact of changes in water quality, the findings cannot be directly collated into an overall impact (costs and benefits) analysis, as to do so would risk comparing apples (impacts of quality changes) with oranges (impacts of quantity changes).

Given this context, a sample of eight 'case-study' hydro schemes were selected for examination. These schemes collectively account for approximately 93% of New Zealand's hydro generation, plus span the range of different hydro scheme characteristics in terms of: scale, storage capabilities, numbers of stations in a scheme, and water sources. In addition, an evaluation was undertaken on the Huntly power station whose ability to use the Waikato river for cooling could be impacted by altered minimum flows.

Modelling was undertaken for each scheme to determine the likely outcomes that would occur from altering the minimum flows in the rivers associated with each scheme. Such modelling was done on a scenario basis, with similar altered minimum flow scenarios applied to each scheme. Two types of scenario were considered:

- Increasing minimum flows above existing consented levels by a set percentage (10% or 40%). In some cases such scenarios were infeasible given the physical characteristics of the scheme[1]. Accordingly no model runs were done for such situations.
- Setting minimum flows at a fixed % of natural minimum flows (40% or 80%). In some cases this would have resulted in a *reduction* in minimum flows relative to the current situation. Accordingly, such instances were not included in the study.

The modelling exercise consisted of two main parts:

- Firstly, the owners of the schemes (namely the five main generators in New Zealand[2]), each undertook modelling to estimate the pattern of generation for their individual schemes as a result of the altered minimum flow scenarios;
- Concept then modelled the potential electricity system costs arising as a result of these altered generation patterns.

The scope of this exercise was purely to investigate the electricity market outcomes of such altered minimum flows. It did not evaluate any other potential externality impacts arising from altered hydro generation outcomes or from any replacement non-hydro generation. (e.g. altered amenity outcomes relating to the hydro rivers and lakes, or environmental / societal externalities relating to the development of replacement non-hydro generation).

Results & Conclusions

Nature of impacts on electricity system arising from altered minimum flows

The analysis in this study demonstrates that increasing the minimum flow requirements on rivers used for electricity generation will impose costs on the electricity system as measured by a number of potential metrics:

- Whole-of-New Zealand resources cost implications (i.e. the economic cost implications) arising from the need to replace lost hydro generation with non-hydro generation, thereby incurring the associated fuel, CO_2, capital and operating costs.
- Lost revenue to the owners of such electricity generation; and
- Increases to electricity consumer bills.

The principal focus of this study has been on the first bullet point – i.e. the economic cost implications – although the study does also address the likely implications for the other measures.

Such increased costs will primarily arise from two main phenomena:

- ***Reduced diversions*** into rivers used for electricity generation arising from increasing the minimum flow requirements in waterways from which water has been diverted.
- ***Loss of flexibility*** from reduced ability for hydro generators to store water at low value times for use at high value times. This loss of flexibility arises because generators:
    a) Will need to release more water at some low value times (generally times of low demand) in order to meet increased minimum flow requirements at such times. This released water will

[1] Situations where increasing minimum flows would be infeasible are where minimum flows at a point in the river are already close to natural minimum flow levels, and the scheme does not have large amounts of storage which can be used to raise minimum flows above these natural levels. This applied to minimum flows at the bottom of the Clutha (hence only altered minimum flows further up the Clutha scheme were considered), and the Waikato scheme.

[2] Contact Energy, Genesis Energy, Meridian Energy, Mighty River Power, and Trustpower.

therefore no longer be available for use at higher value times (generally times of higher demand); and

b) Will need to hold more water back in their reservoirs to ensure they can meet increased minimum flow requirements if inflows over the subsequent days / weeks / months[3] turn out to be low – i.e. in case of a 'dry' inflow sequence. On average[4] this water will be held back during higher value periods than those during which it is subsequently released. Operating the reservoirs more conservatively in this fashion may also result in increased spill if subsequent inflows turn out to be very wet. This increased spill will result in less water being available for hydro generation at other times.

Such impacts can be summarised as:

- An ***absolute loss of hydro generation*** output across the year due to reduced diversions and increased spill; and
- A ***temporal shifting of hydro generation output between time periods***. In general such shifting is away from higher value periods (i.e. peak demand periods on both a seasonal and diurnal basis) and to lower value periods.

Any absolute loss hydro generation will need to be replaced by non-hydro generation. Given that the variable cost of the lost hydro generation is close to zero, the net cost of such replacement generation is likely to be significant.

Where hydro generation is time-shifted from periods of higher demand to periods of lower demand, the cost of replacing the hydro generation from the higher demand periods will be partially offset by displacing the cost of the non-hydro generation for the lower demand periods. However, given that the cost of non-hydro generation during higher demand periods is materially higher than during lower demand periods, the net cost impact will still be material.

[3] Schemes with small reservoirs require storage and release decisions on the timescale of a few days, whereas schemes with very large reservoirs (e.g. the Waitaki scheme) require storage and release decisions on the timescale of 4-5 months.

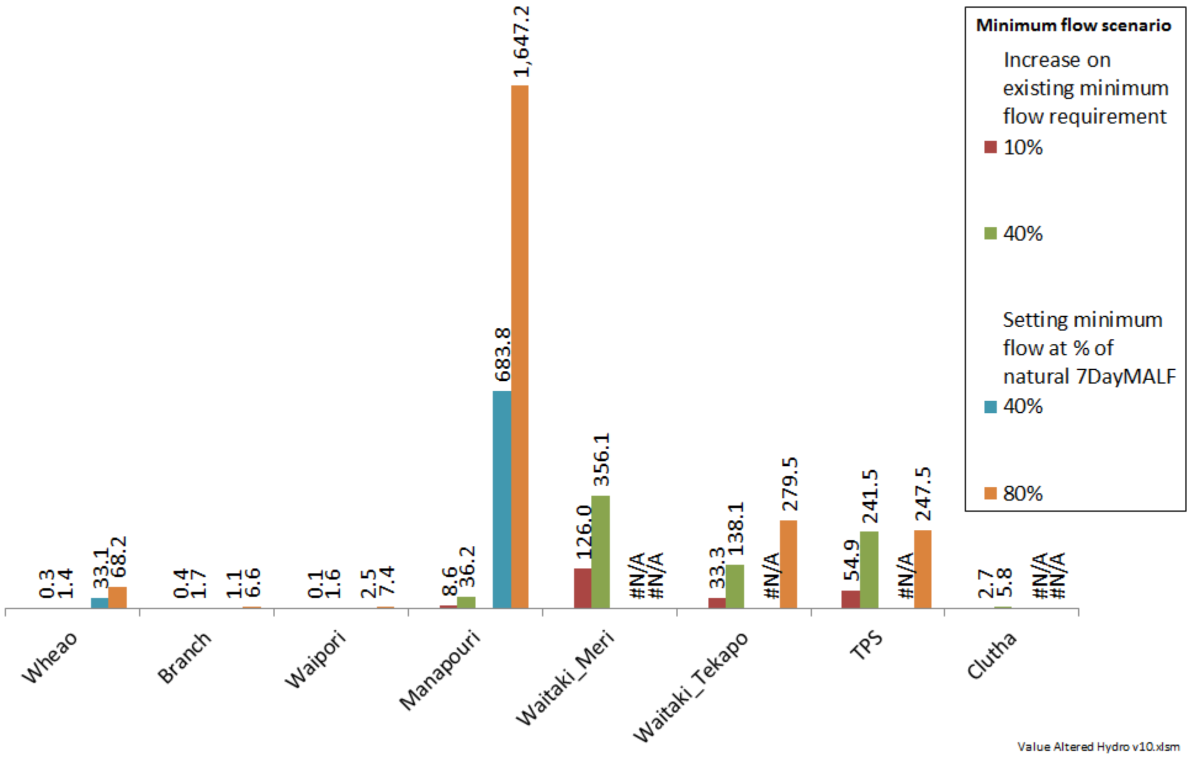
[4] Due to the uncertainty over future inflows, it is possible that in some instances the altered pattern of hydro generation may turn out to be 'fortuitous'. However, on average it would be expected that generators would not be able to optimise their hydro storage and release decisions as well as they would otherwise have been able.

Potential scale of impact on electricity system arising from altered minimum flows

The following graphs set out the analysis which demonstrates the above phenomena, and which also emphasises how the scale of such impacts can vary significantly between schemes due to material differences in the characteristics of such schemes[5].

The figure below demonstrates the scale of electricity cost impact will vary significantly from river to river[6].

Figure 1: Estimated scale of impact on electricity system costs (i.e. economic costs) for different hydro schemes and minimum flow increases (25 yr $m NPV cost) [7 8]



Some of this variation in cost impact arises from simple variation in the size of river and associated hydro scheme.

5 It should be noted that generator analysis was not provided for some schemes and some scenarios. However, it is considered that a sufficiently large number of case-study schemes were provided, which span the range of scheme characteristics, in order to robustly demonstrate the potential nature and scale of altered minimum flow regimes on rivers used for electricity generation.

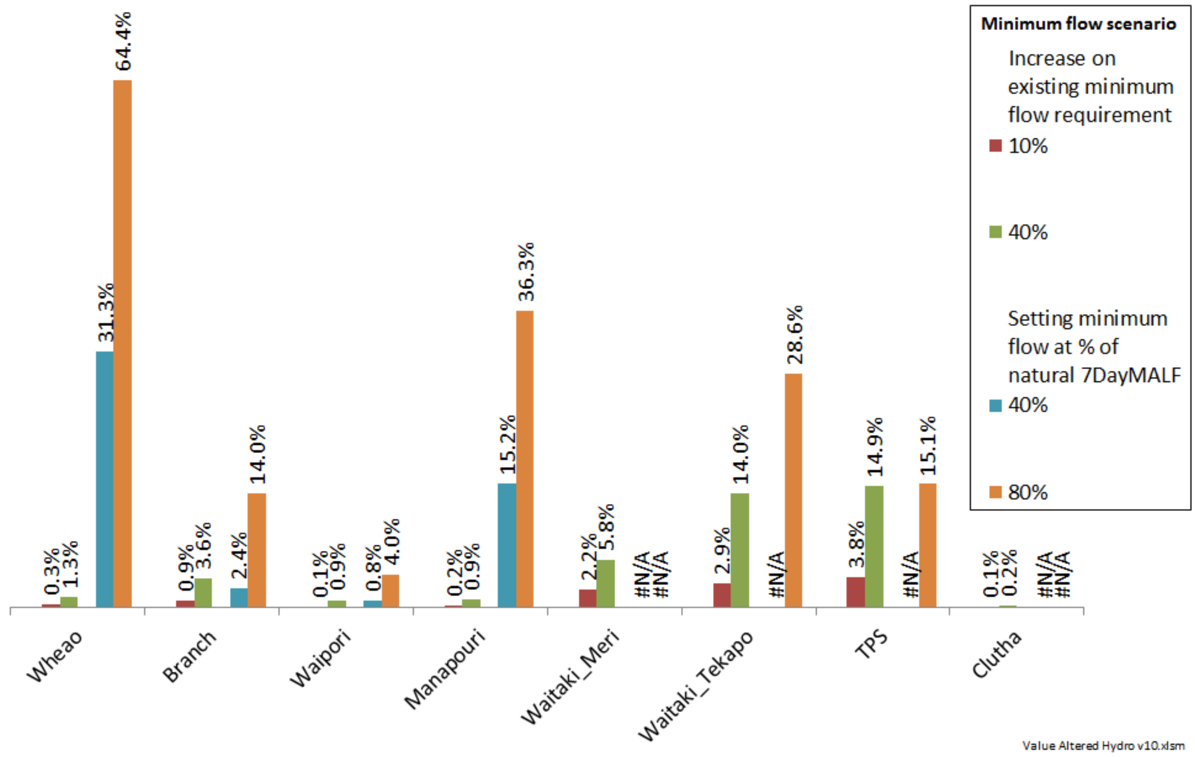
6 The metric for demonstrating cost impacts is the Net Present Value of the electricity system costs measured over 25 years using an 8% discount rate. This metric was chosen as it is considered to best represent the long-lasting system consequences of altering hydro-generation capabilities.

7 Because the Waitaki scheme has been split between Genesis Energy (which owns the Tekapo stations) and Meridian, (which owns the rest) the analysis has distinguished between these two as Waitaki_Tekapo and Waitaki_Meri, respectively. '7DayMALF' stands for seven day mean annual low flow, and is a measure of the minimum flow levels that occur naturally in the river.

8 Meridian provided information as this report was being finalised which suggested that their earlier modelling of the Waitaki (which formed the basis of the results in this report) probably under-estimated the scale of impact by approximately 10%. However, there was insufficient time to incorporate such updated analysis into the final report.

However, when looking at the cost impacts as a proportion of the total value of the scheme, it can be seen that the proportional impact varies significantly between different schemes and scenarios. This is indicated in the following figure.

Figure 2: Cost impact of altered minimum flows represented as a proportion of a scheme's total value



This significant variation between schemes in the nature and scale of impacts arising from altered minimum flow scenarios are driven by a number of key factors which vary significantly between schemes:

Firstly, whether the increased minimum flow results in reduced diversions into a river, or reduced flexibility within a river. The cost consequences of losing water from diversions into a river are generally much greater than reduced flexibility within a river[9].

The second factor driving the difference in impacts between schemes is how the current level of consented minimum flows applying to a river compare with natural minimum flows. Thus,

- If a river currently has a low consented minimum flow relative to natural minimum flows, a 10% increase on such a low minimum flow level will have a relatively small impact compared to a 10% increase on a minimum flow which is much larger compared to natural minimum flows.
- However, if a scheme is already operating to a minimum flow which is close to (or even above) natural minimum flow levels, it may not be physically possible to increase minimum flows

[9] In this respect, it is worth noting that the high costs attributed to the Waitaki scheme are in large part due to reduced diversions 'within' the scheme – thus currently water is diverted out of the Tekapo and Pukaki rivers and fed into the generating stations at the top half of the Waitaki chain. Increasing the minimum flows in the Tekapo and Pukaki rivers would therefore result in a lot of water bypassing the generating stations in the top half of the scheme. If only the minimum flows at the bottom of the chain were increased (i.e. for the lower Waitaki, but not for the Tekapo or Pukaki rivers), the scale of losses would be significantly less.

further above such natural levels unless the scheme has significant amounts of seasonal storage[10].

The third factor driving the difference in impacts between schemes is the difference in the MWh/cumec conversion ratio for different rivers. Thus:

- the design of some hydro generators means they are able to generate significantly more electricity per cumec of water than other hydro generators.
- some hydro schemes are comprised of a chain of generators along a river meaning that a cumec of water will be used for electricity generation many times along that chain.

This difference in MWh/cumec conversion factors means that the loss of a cumec of water can have very different electricity system impacts depending on where it is lost from. For example, reduced diversions feeding into the top of the Tongariro Power Scheme (TPS) (which subsequently feeds into the Waikato scheme) would result in the loss of approximately 4.5 times more generation than the same quantity of water lost through reduced diversions into the Manapouri scheme.

The fourth factor driving the difference in impacts between schemes is the difference in the general seasonal timing of inflows for a scheme and whether they are generally naturally correlated with demand (e.g. Waikato) or not (e.g. Waitaki). Generally, if seasonal inflows are correlated with demand it is likely that there will be a greater cost impact on seasonal storage and release decisions than if inflows are anti-correlated with demand[11].

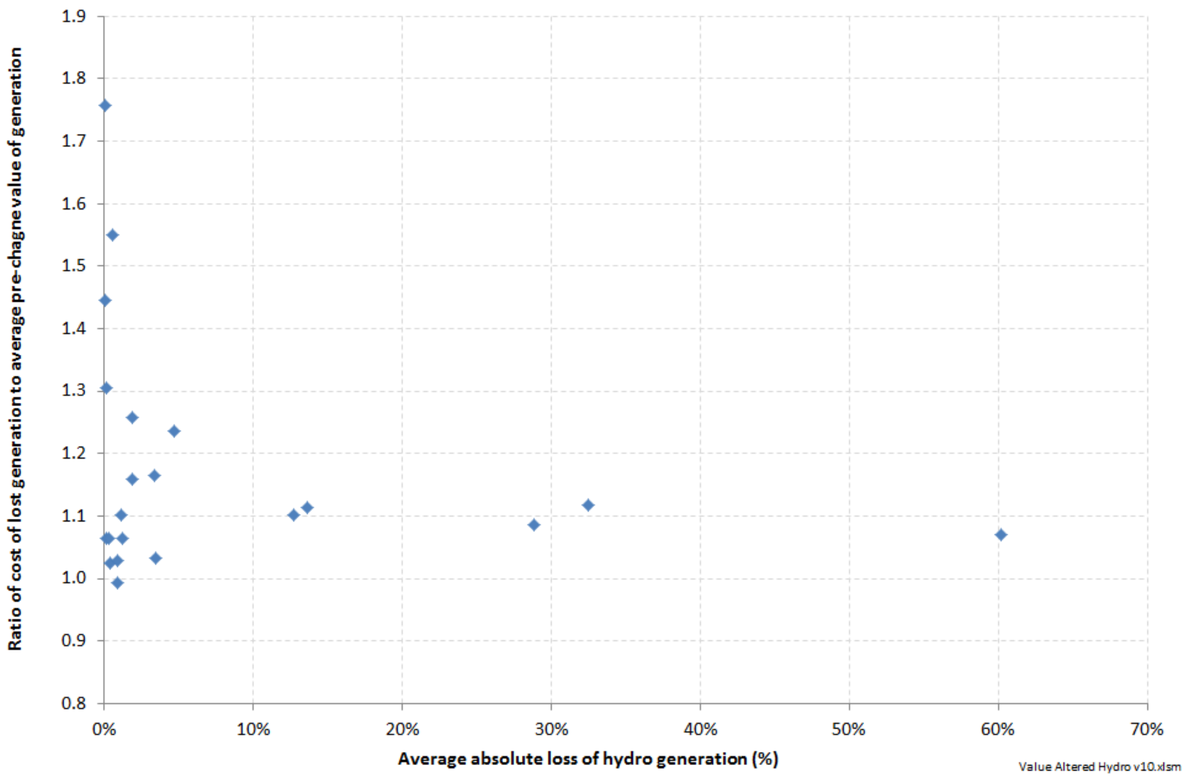
The last factor driving the difference in impacts between schemes is the difference in the extent of storage reservoirs on the river, and thus the ability to manage flexibility impacts. The nature of this impact is very scheme specific, and varies in a non-linear fashion with respect to increasing minimum flows within a scheme. These different flexibility impacts results in significant differences in the types of altered non-hydro generation outcomes in terms of changes to baseload, mid-merit and peaking non-hydro plant.

Given the significant variation in all of the above, it is hard to generalise about the cost impacts. However, where increased minimum flows results in significant loss of generation (particularly through reduced diversions), modelling indicates that the $/MWh value of this lost generation is likely to be approximately 10% - 20% greater than the average $/MWh value of the scheme's generation prior to the change. This is indicated by the following figure.

10 For example, the lack of significant seasonal storage for the Clutha scheme means it would be unable to materially increase consented minimum flows at the bottom of the scheme as they are already above natural minimum flow levels. Similarly, the modelling suggests that it would not be feasible to increase minimum flows in the Waikato scheme beyond a certain point without resulting in breaching Taupo minimum lake levels during dry years. This would be exacerbated if increased minimum flows for the TPS diversions reduced the amount of water flowing into Taupo. These physical constraints have meant that it has not been possible to model increased minimum flows for the bottom of the Clutha at all, or the Waikato above a certain level as it becomes infeasible.

11 Increased minimum flow requirements require hydro generators to hold more water in storage to manage potential future low inflow periods. If such low inflow periods are most likely to occur over summer, this will require the hydro generator to hold more water back during the winter and spring. However, the winter and (to a lesser extent) spring periods are when demand is greatest and generation is at its most valuable.

Figure 3: Plot of ratios of cost of lost generation to average pre-change value of generation[12]



As can be seen, as indicated by ratios greater than 1, the cost per MWh of this lost generation is almost[13] invariably greater than the average value of electricity from the scheme prior to such changes. This reflects the fact that increased minimum flows reduces the flexibility of hydro generators to store water at low value times for use at high value times.

Cumulative effects of multiple rivers facing increased minimum flows

It should be noted that the cost estimates produced in this analysis are based on evaluations of individual schemes in isolation. It is considered that simply summing the costs for each of the individual schemes to estimate a total New Zealand cost if all schemes were to have their minimum flows increased by the same amount would not be appropriate for two reasons:

12 This analysis attempts to 'normalise' the cost impacts for different sized schemes. This was done by calculating the $ cost of the altered hydro generation (i.e. due to reduced diversions and reduced flexibility) and dividing by the MWh of lost generation. This $/MWh value was then compared as a ratio with the average $/MWh value of the scheme's generation before the change in minimum flow.

13 There are a couple of data points which indicate that the average cost of the lost generation was less than the average pre-change value of the generation. It is suspected that these are the result of inaccuracies in modelling of the altered generation outcomes as such a result would indicate that the loss of generation would enable the scheme to improve the optimisation of its water.

1) It is understood that there is absolutely no policy driver for considering such a "one-size-fits-all" approach for minimum flows on rivers[14]; and

2) Altered hydro generation outcomes for one scheme will affect the storage and release decisions for other hydro generators. Accordingly, a 'true' estimation of these cumulative cost impacts would require more sophisticated whole of New Zealand hydro modelling than has been undertaken by the generators individually. That said, initial analysis suggests that the cumulative $m impact of several schemes having altered minimum flow regimes is unlikely to be radically different to summing the individual $m impact of each scheme – although potentially a lower bound.

Impact on consumers' bills

The principal focus of this study has been to consider the economic cost impacts on New Zealand – i.e. estimating the cost of altered fuel burn, other operating costs, and capital investment requirements. However, it is also the case that altered hydro generation outcomes could impact on consumers' bills through higher consumer prices. Such an outcome could arise if the loss of any hydro generation requires the building of progressively more expensive replacement generators[15]. In other words:

- if each new generator costs more to build than the last, there would likely be a consumer price impact in addition to the economic cost impact; whereas
- if each new generator costs the same to build as the last, there would only be an economic cost impact, but no consumer price impact[16].

Analysis indicates that New Zealand does face an upward sloping new generation cost-supply curve as there is considerable variation in the cost of New Zealand's new generation options – particularly driven by variations in the characteristics of the different new renewable generation options. The slope of this cost-supply curve suggests that the $m magnitude of an increase in all New Zealand consumers' bills will be very similar to the $m magnitude of the economic cost impacts shown in Figure 1 above[17], with the scale of impact depending on which hydro schemes face altered minimum flows and by how much.

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[14] Officials have advised that the policy as noted in the "*Freshwater reform 2013 and beyond*" discussion document is:
- Regional Councils will continue to make decisions about freshwater management in their region.
- The proposed policy is to introduce environmental bottom lines and a national objectives framework
- In order to meet these objectives, Regional Councils *may* decide to implement minimum flows across some of their catchments. These decisions would take time and involve significant community engagement.

In other words, Regional Councils will continue to decide on arrangements for rivers within their region, and the purpose of this study is to understand what the broad impact might be *if* Regional Councils decided to implement minimum flows.

[15] This is based on analysis of price impacts in the long-run using a framework whereby prices, over-time, must be equivalent to the long-run marginal cost of new generation supply. If prices do not reach such a level over time, it would be expected that there would be insufficient new generation built to meet demand growth.

[16] This outcome arises due to the fact that prices, in the long-run, will need to be at a level equal to the long-run marginal cost of the marginal source of new supply. If there is no difference in the cost of different sources of supply (i.e. there is a flat supply curve), then there will be no change in price associated with differences in where the demand curve intersects with the supply curve. However, if new supply gets progressively more expensive (i.e. an upward sloping supply curve) then prices will be higher if the demand curve intersects a higher point on the supply curve.

[17] This similarity between $m consumer bill impacts and $m economic cost impacts is purely a coincidence of the slope of the new-entrant cost-supply curve, rather than being driven by any inherent feature of markets which would give rise to such a relationship.

Thus, the impact on consumer bills of a 40% increase in minimum flows for the Wheao scheme will be relatively insignificant (approximately a 0.002% increase on domestic consumers' bills), whereas for the Waitaki scheme the impact of a 40% increase in minimum flows would start to become more material (approximately a 0.35% increase on domestic consumers' bills). It is considered that the cumulative impact on consumers bills' of several schemes facing altered minimum flows would be additive rather than multiplicative[18].

Such a price effect would also result in an aggregate wealth transfer to generators, and a net gain to those generators not directly affected by the loss of generation.

Transitional impacts

The cost estimates set out above are based on the altered resource cost implications once the market has shifted to a new supply-demand equilibrium.

However, immediately following any change to altered minimum flow regimes the market may be in a situation of dis-equilibrium which could give rise to different cost outcomes – at least until demand growth and generation new-build / retirement transitions the market to a situation of supply-demand equilibrium again.

It is very difficult to assess the likely nature and scale of such short-term impacts as they are heavily dependent on:

- whether the cycle of new-build and retirement means the market is in a situation of over- or under-supply when such changes occur; and
- how much advance notice is given of a change in minimum flows, and thus the extent to which such information can be factored into new-build / retirement decisions ahead of time.

Despite these inherent uncertainties, in general it would be expected that these short-term impacts would result in higher $/MWh costs than the long-term costs as the market would move into a situation of relative scarcity.

Other impacts

The principal focus of this study has been on electricity cost impacts arising from altered hydro generation outcomes. However, it should be recognised that there would likely be other impacts from such altered generation outcomes including:

- potential increased risk of flooding in some areas;
- reduced amenity benefits for some water bodies;
- adverse environmental outcomes from an increase in non-hydro generation;
- potential negative environmental outcomes associated with altered river and lake levels; and
- reduced ability to meet other policy objectives such as 90% renewable electricity generation by 2025.

It is beyond the scope of this exercise to evaluate the nature and scale of such potential impacts.

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[18] It should be noted that the electricity price consumers' face is not just driven by electricity wholesale prices, but also due to a number of other factors such as transmission and distribution charges, retail operating costs, and retail competition outcomes. It is not considered that changes in hydro generation would impact these other factors, and thus have been held constant for this analysis.

1 Introduction

The Water Directorate (developed by the Ministry for the Environment together with the Ministry for Primary Industries and the Department of Conservation) is considering a range of possible policy options to improve New Zealand's freshwater management.

As part of the process of trying to determine which potential water management changes are likely to deliver greatest benefit to New Zealand, the Water Directorate is currently seeking to estimate the potential economic impact of the introduction of a national objectives framework (NOF), including national bottom-lines for water quality attributes, on existing and future users of freshwater across a range of different commercial sectors and non-commercial users.

One such sector is the electricity generation sector where freshwater from rivers and lakes is used to generate electricity directly through hydro power schemes, and indirectly through providing cooling capabilities for some thermal power schemes.

This report seeks to evaluate the potential economic impact of altered power generation outcomes arising from altered minimum flow regimes on various rivers which are used for electricity generation.

It is understood that there are no specific proposals relating to altered minimum flows for New Zealand's rivers, either on a national or individual river basis. The recent discussion document released by MfE "*Freshwater reform 2013 and beyond*" reaffirmed that regional councils will continue to make decisions about freshwater management at a catchment level.

Rather, the intent of this exercise is to highlight the potential nature and scale of economic impacts on electricity generation *if* some rivers were to have increased minimum flow requirements – in effect a change in available water *quantity*.

Concept understands that parallel studies are also underway considering the potential impact of national bottom lines for water *quality* attributes. With regards to the relationship between these two types of studies, MfE have advised that whilst this report examining the electricity sector will be useful information for officials to consider alongside the assessments of the impact of changes in water quality, the findings cannot be directly collated into an overall impact (costs and benefits) analysis, as to do so would risk comparing apples (impacts of quality changes) with oranges (impacts of quantity changes).

Because every hydro scheme operates within a unique combination of natural, physical and legal conditions, it would likely be inappropriate to imply an effect on a given scheme from the results of another. For this reason this study has sought to examine the practical range of impacts for a sample of eight 'case-study' hydro schemes:

- Waitaki (which for this analysis has been split into "Waitaki_Tekapo" corresponding to the Tekapo A & B stations owned by Genesis Energy, and "Waitaki_Meri", corresponding to the remainder of the scheme owned by Meridian)
- Manapouri
- Clutha
- Tongariro Power Scheme (TPS)
- Waikato
- Waipori
- Wheao

- Branch

These schemes collectively account for approximately 93% of New Zealand's hydro generation, plus span the range of different hydro scheme characteristics in terms of: scale, storage capabilities, numbers of stations in a scheme, and water sources. In addition, an evaluation was undertaken on the Huntly power station whose ability to use the Waikato river for cooling could be impacted by altered minimum flows.

Modelling was undertaken for each scheme to determine the likely outcomes that would occur from increasing the minimum flows in the rivers associated with each scheme. Such modelling was done on a scenario basis, with similar minimum flow increase scenarios applied to each scheme. Two types of scenario were considered:

- Increasing minimum flows above existing consented levels by a set percentage (10% or 40%). In some cases such scenarios were infeasible given the physical characteristics of the scheme[19]. Accordingly no model runs were done for such situations.
- Setting minimum flows at a fixed % of natural[20] minimum flows (40% or 80%). In some cases this would have resulted in a *reduction* in minimum flows relative to the current situation. Accordingly, such instances were not included in the study.

The modelling exercise consisted of two main parts:

- Firstly, the owners of the schemes (namely the five main generators in New Zealand[21]), each undertook modelling to estimate the pattern of generation for their individual schemes as a result of the altered minimum flow scenarios;
- Concept then modelled the potential electricity system costs arising as a result of these altered generation patterns.

This two-fold approach was deemed appropriate because the pattern of operation of each hydro scheme is very scheme-specific and requires scheme-specific modelling. It was felt that the generators themselves were likely to have the most comprehensive such models for their schemes. Plus, by using a common approach for the second-phase evaluation, it helped ensure an internally-consistent approach to estimating the system cost consequences.

It should be noted that the scope of this exercise was purely to investigate the electricity market outcomes of such altered minimum flows. It did not evaluate any other potential externality impacts arising from altered hydro generation outcomes or from any replacement non-hydro generation. (e.g. altered amenity outcomes relating to the hydro rivers and lakes, or environmental / societal externalities relating to the development of replacement non-hydro generation).

The structure of this report is as follows:

- Section 2 provides an overview of New Zealand's hydro and thermal schemes in general, and highlights the potential issues associated with altered minimum flow requirements for both types of schemes.

[19] Situations where increasing minimum flows would be infeasible are where minimum flows at a point in the river are already close to natural minimum flow levels, and the scheme does not have large amounts of storage which can be used to raise minimum flows above these natural levels. This applied to minimum flows at the bottom of the Clutha (hence only altered minimum flows further up the Clutha scheme were considered), and the Waikato scheme.

[20] The metric for considering natural minimum flow (i.e. the flows expected in the absence of any hydro development) is the seven day mean annual low flow (7DMALF).

[21] Contact Energy, Genesis Energy, Meridian Energy, Mighty River Power, and Trustpower.

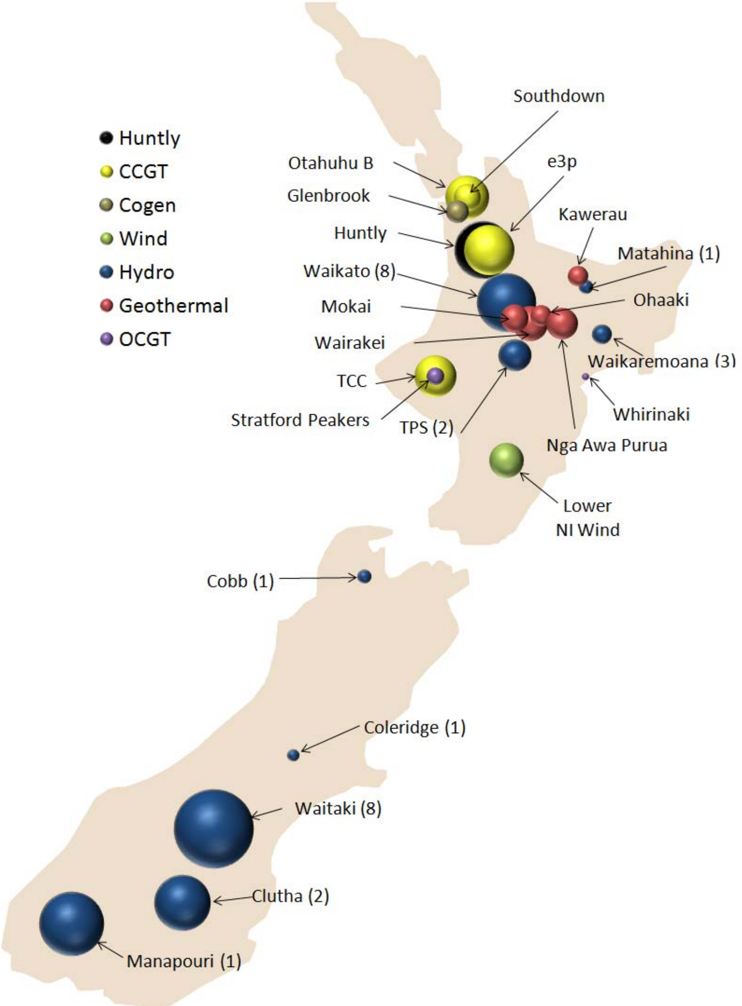
- Section 3 outlines the methodologies used by Concept to estimate the system cost and consumer price outcomes arising from the altered generation outcomes.
- Section 4 sets out the key conclusions from this exercise.
- Appendix D provides a detailed description of each of the schemes, and presents the results of the modelling undertaken by the generators relating to the altered generation outcomes.
- The other Appendices provide more detailed description of various electricity sector phenomena which give rise to the outcomes described in the main body of the report.

2 Overview of fresh water use for electricity generation in New Zealand

2.1 Electricity generation in New Zealand

New Zealand's electricity is generated by a variety of renewable and fossil-fuelled power stations. Figure 4 shows the location of the main power stations in New Zealand.

Figure 4: Location of the main generation schemes in New Zealand[22]



In addition to hydro stations, fresh water is also critical to the operation of some of New Zealand's thermal and geothermal power stations where it is used as a cooling source[23]. Figure 5 shows the

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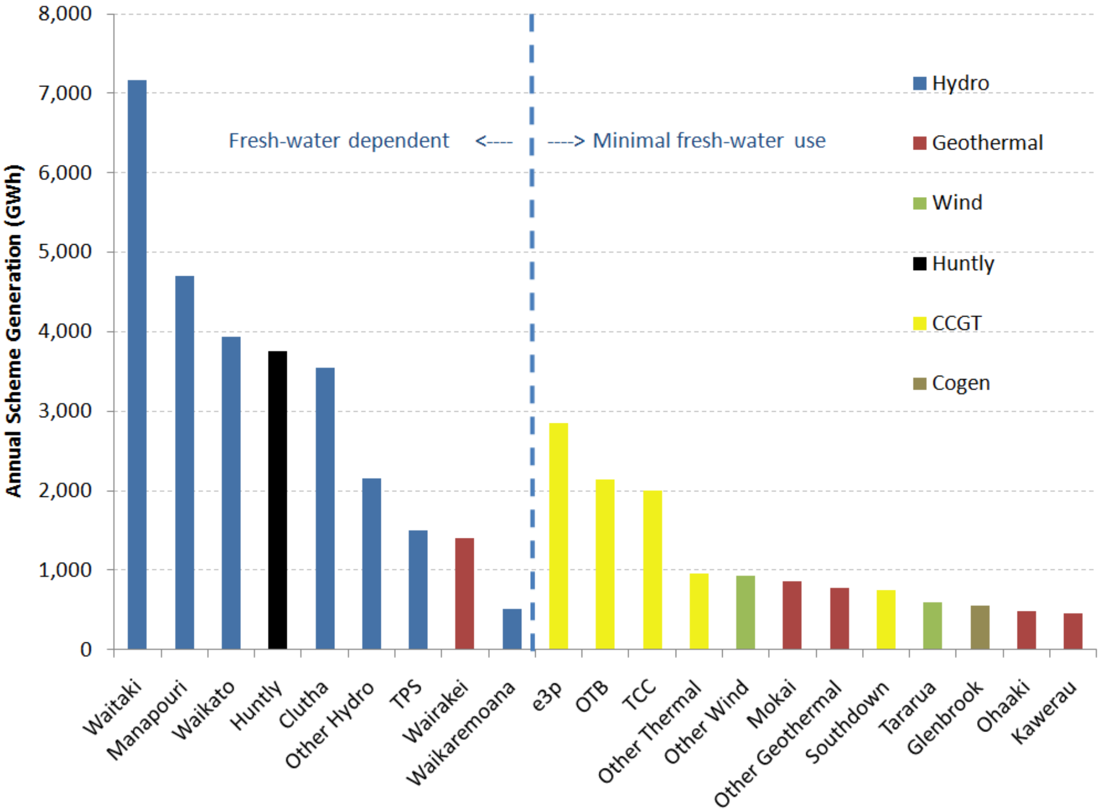
22 The size of the circle indicates the average annual amount of electricity generated by the scheme. For hydro generation, the number of individual stations in each scheme is shown in brackets.

23 Thermal stations work by heating and cooling a fluid (usually steam), and extracting useful energy from the fluid's change in temperature. The larger the temperature difference, the more efficient the plant will be. Access to a source of cooling is therefore important. This can be provided by the atmosphere (air cooling) or a river, lake or sea (water cooling). From an energy efficiency perspective, water cooling is generally preferred because of water's higher heat capacity.

average annual generation of power stations grouped into those that are dependent on fresh water, and those that are not[24].

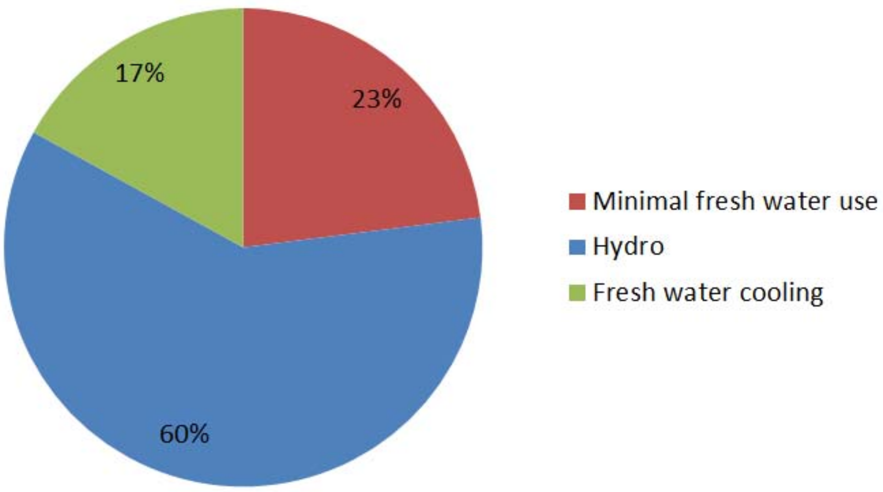
Figure 5: Average annual generation over the period



On average, approximately three-quarters of all electricity generated in New Zealand is dependent on access to fresh water, and hydro-electric stations alone account for 60% of total power production.

[24] The 'fresh-water dependent' list only includes hydro generation stations and thermal or geothermal stations that use fresh water for cooling purposes. Other thermal stations may require fresh water for use in boilers, or for water injection. While still significant, the volume of water required for these uses is much less than for cooling purposes, and these stations have not been classified as 'water dependent' in the chart.

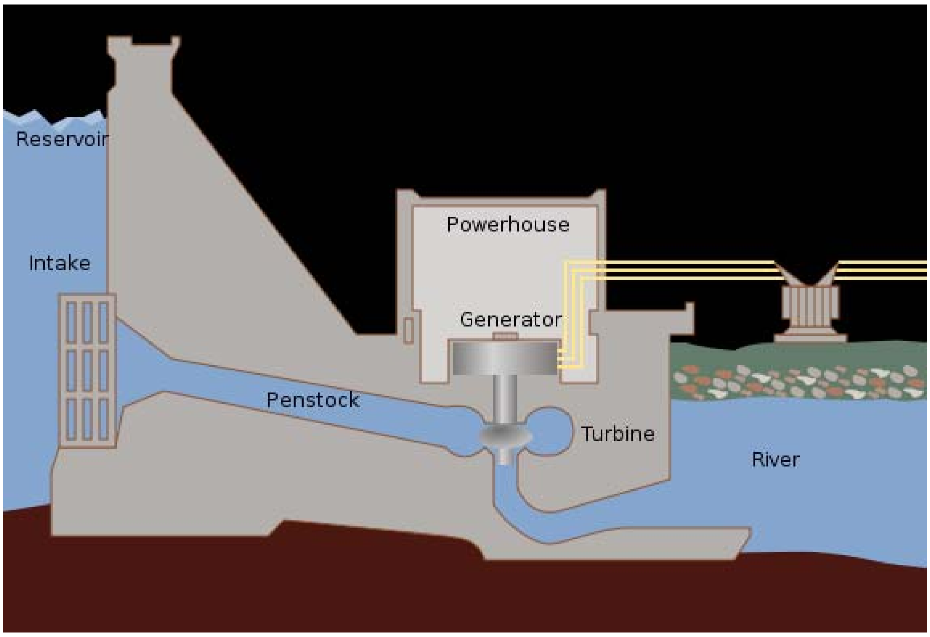
Figure 6 – Proportion of average annual GWh generated



2.2 Hydro generation

Figure 7 illustrates the operation of a typical[25] hydroelectric station. A dam (or natural structure) is used to create a reservoir. Water from the reservoir is passed through the penstock to spin a turbine and create electricity. The vertical distance between the top of the reservoir and the turbine is referred to as the hydraulic head. High head hydro stations can generate more electricity per unit of water flowing through the turbine.

Figure 7 - Example Hydroelectric Station



[25] This description covers the design of the dam-based hydro schemes that generate the majority of electricity in New Zealand. However, there are other canal-based hydro schemes where the generator effectively sits more in-river, and does not have a dam with a lake behind it.

While New Zealand's hydro generation schemes share the same basic technology, there is significant variation in many key characteristics including:

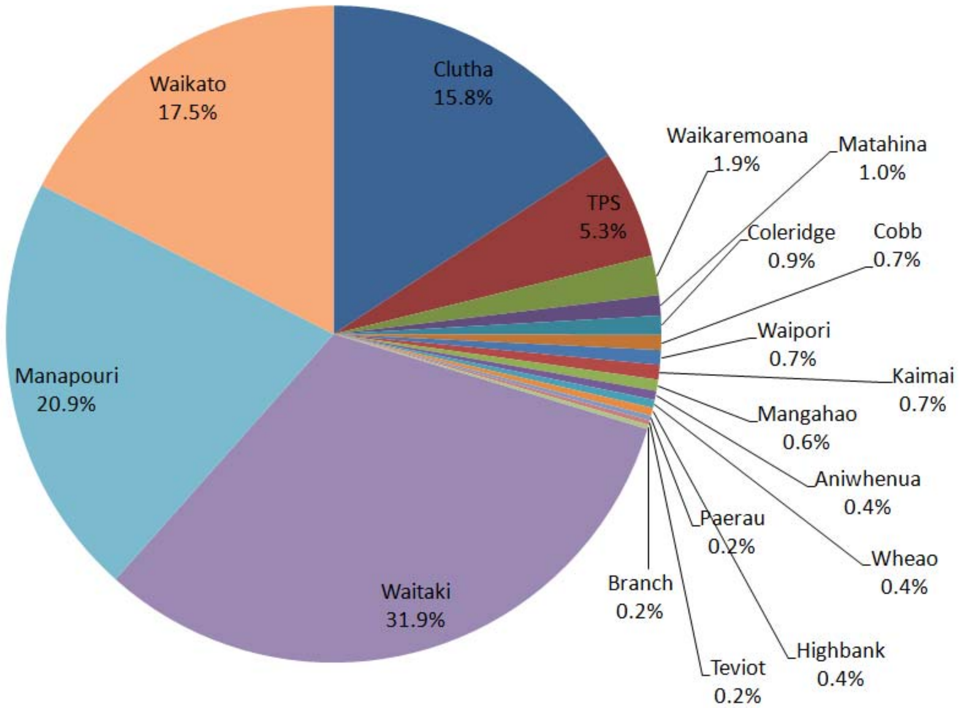
- size (being a function of the head of the scheme, the volume of water available for generation, and the generation capacity of stations in the scheme);
- the amount of hydro storage in each scheme;
- the timing of typical within-year hydro inflows into the scheme[26];
- whether the scheme consists of a single power station, or a chain of interconnected power stations;
- the extent to which water is diverted from one river to another to increase hydro generation;
- the electrical 'location' within the national grid;
- the specific ecological characteristics of the river system (noting that there can be significant differences in flora and fauna, and the volume and variability of flows along the river);
- other specific environmental factors including tangata whenua, cultural, amenity, recreational, landscape and natural character values; and
- the nature and scale of other potential uses for water in a catchment.

One of the consequences of such diversity of characteristics is that the consents governing the use of such water for electricity generation are themselves very diverse to reflect the situation-specific nature of the waterbodies. The situation-specific complexity of the issues, coupled with the extensive community and science-based consultative nature of the consenting process, results in consent conditions which often run to hundreds of pages in length, and which cover a range of ecological, cultural, recreational, and economic requirements and phenomena. In many instances, the outcome of the consenting process results in a number of beneficial environmental or community outcomes through actions undertaken by the owner of the scheme to mitigate any effects identified with its operation.

26 For example, Waikato monthly inflows are broadly correlated with national demand in that highest inflows tend to occur in the winter months, whereas Waitaki inflows are more anti-correlated with demand as the winter months tend to have the lowest inflows.

The relative size of New Zealand's hydro generation schemes in terms of average annual production is shown by Figure 8 below.

Figure 8: Relative size of hydro schemes - average annual production (GWh)



New Zealand's hydro schemes also differ in their level of hydro storage capacity. Some hydro generation has no useful storage at all, and is referred to as 'run-of-river' because the level of generation is depends entirely on natural water flows. Other hydro generation can be controlled to some extent by managing the rate at which water is released from natural or man-made storage reservoirs.

Hydro generators with storage reservoirs can choose to store and release their water in such a fashion as to target their generation at periods of highest demand given the uncertainties around future inflows. For some hydro schemes the size of storage is relatively small such that their storage and release decisions are limited to within-day or within-week decisions. Typically such schemes will aim to target their generation towards periods of highest demand within the day – i.e. morning and evening peaks – and away from periods of lowest demand – i.e. overnight. Other hydro generators have much greater storage capabilities, and can additionally seek to sculpt the release of the water on a seasonal basis – i.e. away from the lower demand summer months, and towards the higher demand winter months.

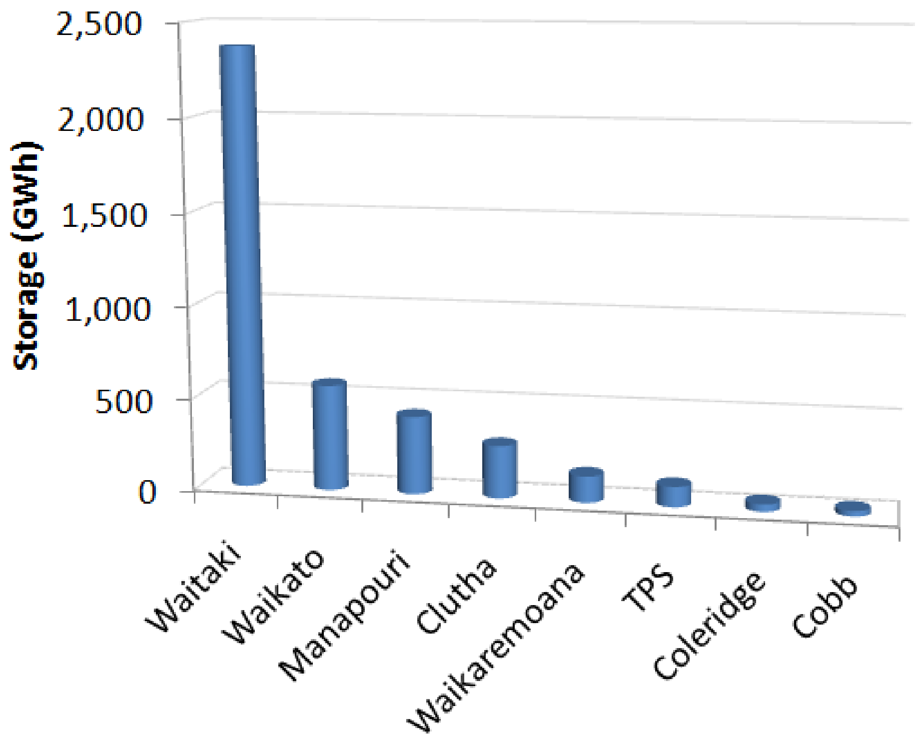
These storage and release decisions are heavily constrained by uncertainty over future inflows. For example, releasing water in one period means it is no longer available for future periods. If future inflows turn out to be 'dry', the early release could prove to be a costly decision, whereas if future inflows turn out to be 'wet' the early release would be the right decision. The significant variability and uncertainty over future inflows (not just for the scheme in question, but for New Zealand as a whole), coupled with the complex characteristics of the electricity system mean that the storage and release decisions require complex optimisation approaches using sophisticated computer models.

Appendix B gives more detail about such storage and release decisions, and how factors such as altering the minimum flows on rivers would impact on such decisions and the consequential electricity generation outcomes.

Many hydro schemes are effectively a combination of storage reservoirs and run-of-river operations from uncontrolled tributaries which feed into the river below a storage reservoir.

Figure 9 shows the hydro storage capacity associated with each major hydro scheme in New Zealand.

Figure 9: Relative size of hydro schemes – storage capacity (GWh)



In total, New Zealand's hydro storage capacity is around 3,600 GWh or some 5 weeks of winter electricity demand. This capacity is modest when compared to the natural fluctuation in hydro inflows – which can vary between around 20,000 and 28,000 GWh, depending on how wet or dry the year is. The variability is even greater (in percentage terms) over shorter timeframes. New Zealand has low hydro storage capacity compared to other countries that also have a high reliance on hydro generation such as Norway.

The ability of hydro generators to use storage to sculpt their water to meet variations in demand is illustrated in the following diagrams based on historical generation in New Zealand.

Figure 10 - Typical Summer Day

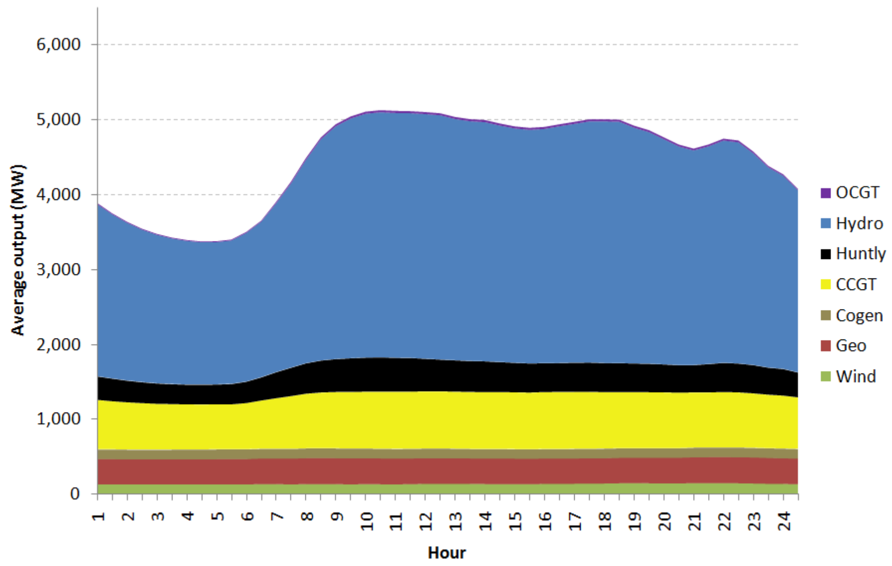
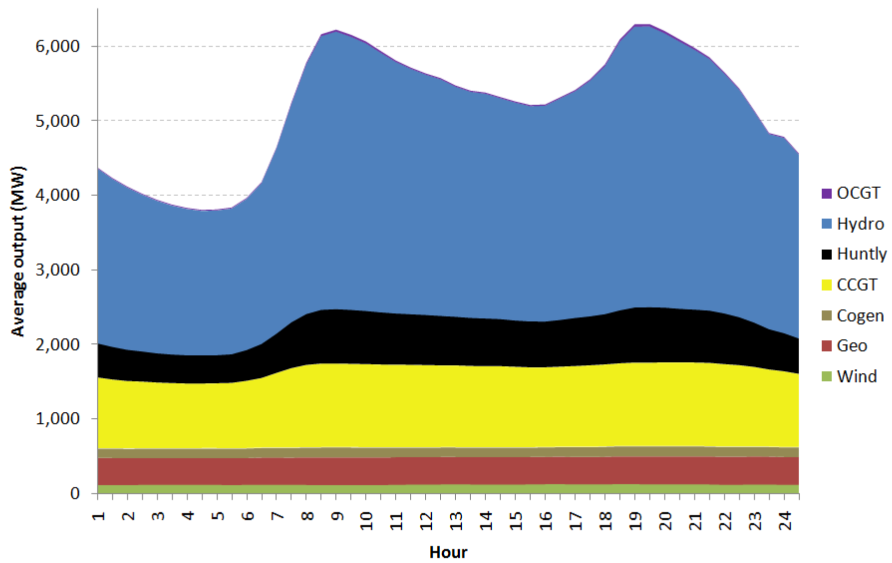


Figure 11 - Typical Winter Day



2.3 Potential impacts on generation from altered minimum flows

2.3.1 Hydro generation

The difference in hydro scheme characteristics outlined above means that:

- different hydro generators face different challenges with respect to seeking to optimise their storage and release decisions; and
- the nature and scale of impact on hydro generation of altered minimum flow requirements will vary significantly between schemes.

For the purposes of this analysis a framework has been developed which distinguishes between generation from:

- consumptive flows (i.e. water that has been diverted from an 'original waterway' into another river for the purposes of electricity generation); and
- non-consumptive flows (i.e. using water in the original waterway).

A change in minimum flows for consumptive schemes (i.e. which use diversions out of one waterway into another) could result in less water being available for electricity generation. I.e. if a minimum flow was increased for the original waterway, less water would be available to be diverted into the river in which the electricity generation scheme is located. This loss of hydro generation would require an increase in non-hydro generation, and likely give rise to an associated increase on system costs and prices. The nature and scale of such cost increases would depend on when this increased non-hydro generation would be required. An increase at times of high demand and/or during so-called 'dry years' will cost significantly more than at times of low demand and/or during 'wet years'.

A change in the minimum flow for non-consumptive flows would impact on the timing of storage and release decisions. The nature of such an impact can be relatively complex and is described in some detail in Appendix B. However, at a high level, the basic impact of a higher minimum flow requirement is that it will reduced a generator's flexibility to store water during low demand periods for use in high demand periods.

Even if there was no net impact on the *annual* GWh of hydro generation from such a loss of flexibility (e.g. 100 GWh of hydro generation was shifted from being generated during high demand periods to low demand periods), such a loss of flexibility would likely give rise to increased system costs. This is because the cost of generating power during high demand periods is significantly higher than the cost during low demand periods. Accordingly, using the example above, the benefit of displacing 100 GWh of relatively low-cost non-hydro generation during low demand periods would be more than outweighed by the cost of having to increase the use of high-cost non-hydro generation during high demand periods.

Further, as described in Appendix B, higher minimum flows for non-consumptive schemes may also lead to an absolute loss of GWh through altering the storage and release decisions of hydro generators in such a way that increased spill would be more likely to occur.

The extent of GWh and flexibility-related impacts due to changes in minimum flow requirements would depend on the amount and location of within-scheme storage, where the additional flow constraints occur (including how many stations are affected by the loss of water), and interactions between various parts of a scheme or with other schemes relying on the same water. The nature of these effects is discussed in the scheme descriptions in Appendix D. Note also that effects will vary depending on whether market conditions are normal or not (for example, dry and wet year impacts will vary).

2.3.2 Thermal generation

Some thermal generators use river water for cooling, and some geothermal generators discharge geothermal fluid into the river.

These activities are governed by comprehensive resource consents established under the Resource Management Act 1991, after consideration of the site specific effects on the environment. Some of these consent conditions require that the discharges from the power stations do not increase the river temperature above a certain maximum level.

These types of consent condition can constrain the ability of a thermal power station to operate. The two generators which have historically been most affected by such constraints are the Huntly power station, and the Wairakei geothermal power station. It is understood that the other major thermal schemes are not materially affected by fresh-water thermal constraints – either because the way they use fresh water for cooling is unlikely to impact on fresh-water heating constraints[27], or they use salt water for cooling, or they re-inject geothermal fluid into the ground.

27 For example, the use of cooling towers will greatly reduce the amount of fresh water required for cooling.

Historically such constraints have tended to bind during the December to April period (i.e. the warmest months of the year when the ambient river temperature tends to be higher), and at times of low river flows (i.e. when the volume of water in the river is not sufficiently great to absorb a quantity of heated water from the power station with heating up beyond the maximum threshold).

Generally an increase of minimum flows in a river should be *beneficial* to thermal generation schemes that use the river for cooling or fluid discharge. This is because increased flowsshould increase the volume of water available to absorb discharged heat.

However, this may not be the case where

- Diversions into a river or waterbody are decreased due to the need to maintain increased minimum flows in the original waterways; and/or

As a result of the loss of flexibility for in-river hydro generators, the river may be operated at close to these minimum levels for a greater proportion of the time than it is currently. This could increase the time when such low levels may constrain the operation of thermal plant.

3 Description of approach to valuing altered generation outcomes

The altered generation outcomes arising from altered minimum flow requirements will likely have cost consequences on the rest of the system. For example:

- hydro generation being *shifted* away from higher demand periods and towards lower demand periods will result in an increase in the need for other generation at such peak times, but a reduction in the need for other baseload generation
- an overall *reduction* in water available for hydro generation (e.g. due to a reduction in the amount of water diverted into hydro schemes, or due to increased spill arising from altered hydro generating patterns) will likely give rise to an increase in the demand for all types of non-hydro generation. The proportionate split in increase between baseload, mid-merit and peaking non-hydro generation will be dependent on the specifics of the hydro scheme in question
- the loss of generation from thermal power stations due to river heating constraints binding more often will require an increase in generation from other stations at such times.

Two different approaches have been adopted to estimate the economic cost[28] to the New Zealand electricity system of the altered generation outcomes modelled by the generators:

- A market price-based approach
- A residual non-hydro generation cost-based approach

These are described in more detail below. Appendix C provides some supporting conceptual analysis around whether such approaches are likely to be reasonable.

3.1 Market price-based approach

The modelling undertaken by the generators has produced projections of altered quantities of hydro generation for different times of the day and year, and for different hydrology states (i.e. dry, wet, etc.). In the majority of situations, the outcome is a reduction in hydro generation, but for some particular time periods and hydro states the outcome may also be an increase in hydro generation (e.g. an increase during night periods at times of low inflows).

The market price-based approach has been to value this altered quantity outcome at the market price associated with the particular time-of day & year and hydro state. For example, the loss of 1 MWh of hydro generation during the middle of the night during a very wet summer will be valued significantly less than 1 MWh of hydro generation lost during the evening peak during a very dry winter.

Figure 12 below shows the array of market prices used to value such altered hydro generation outcomes.

[28] The economic cost represents the whole-of-New Zealand resources cost implications arising from the need to replace lost hydro generation with non-hydro generation, thereby incurring the associated fuel, CO2, capital and operating costs.

Figure 12: Synthetic market price array used to value altered hydro generation outcomes ($/MWh)[29]

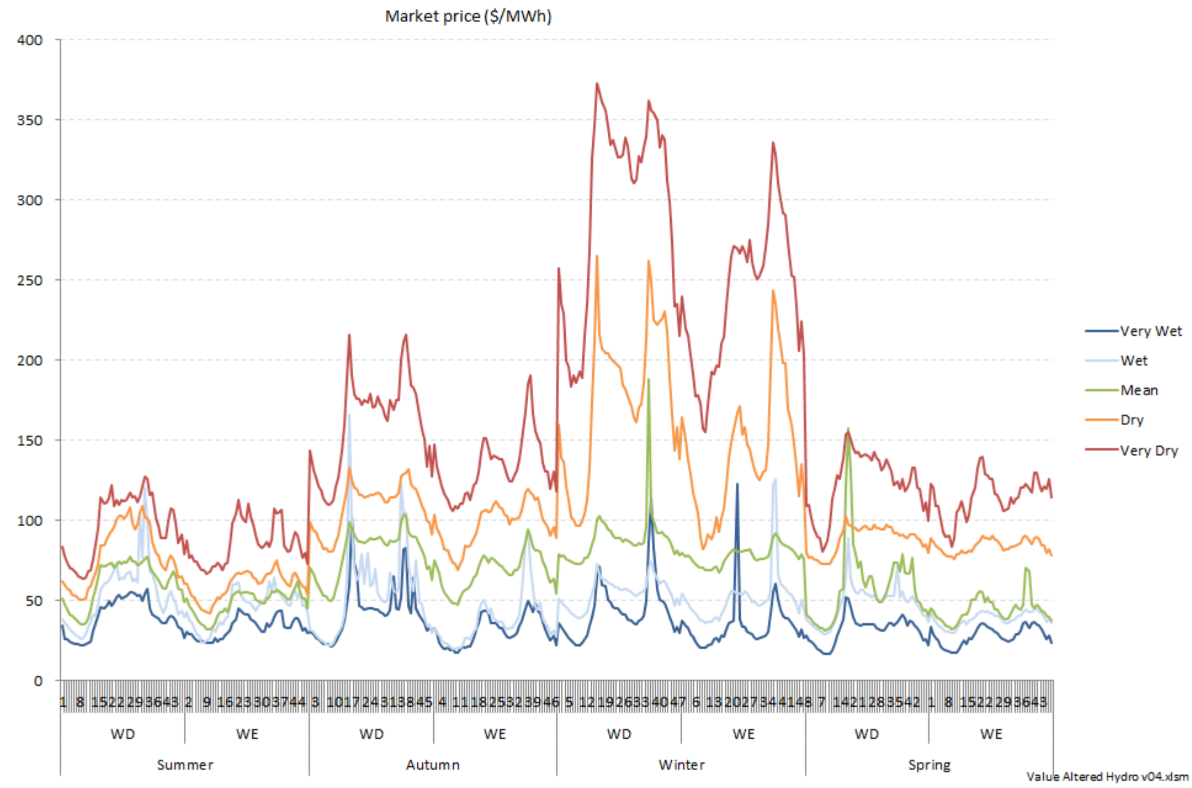


Table 1: Average seasonal prices ($/MWh) for different hydrology states

	Summer	Autumn	Winter	Spring
Very Wet	38	40	40	30
Wet	51	50	54	45
Mean	57	76	85	55
Dry	73	105	166	87
Very Dry	94	153	280	121

This price array has been derived from the observed historical distribution of prices associated with different times of day and year, and different hydrological states for the years 1998 to 2011. In this respect, each season for the historical years was assigned to one of five hydrological quintiles based on consideration of inflows from a whole-of-New Zealand basis.

However, it has been artificially factored to ensure the time-weighted average price across all such periods equals $85/MWh which is estimated to be the approximate long-run marginal cost of new baseload generation at the present time[30].

29 The x-axis is split into four seasons, with a weekday (WD) and weekend (WE) for each season, and 48 half-hours within each day.

30 This estimate has been derived from a variety of sources including: Concept's own modelling of the cost of new generation; statements by various generators in Annual Reports and other such public documents; modelling

This factoring is consistent with the conceptual framework whereby prices must, in the long-run, be sufficient to just cover the long-run marginal cost (LRMC) of the marginal new-entrant generator. If they were systematically lower than this LRMC value, then such generation would not be built to meet demand growth and the market would fall short of generation, whereas if they were systematically higher it would be expected that new generation would be built to capture such excessive rents until they were competed away. The fact that the historical price series from 1998 through to 2011 does not have a time-weighted average that is equal to this current estimate for the cost of the marginal baseload generator is because over the last twelve years the marginal cost of new baseload generation has risen significantly[31].

This same conceptual framework applies to consideration of the need for low-capacity factor plant to meet periods of particularly high demand and/or low hydro inflows. For example, the average of the top 15% of prices in this array is approximately $210/MWh. This not only covers the estimated variable costs (i.e. fuel, CO_2, and variable operating & maintenance (O&M) costs) but is estimated to be just enough to cover the fixed O&M and recovery of capital for a new open-cycle gas turbine (OCGT) peaker. Again, if prices for a given capacity factor of operation were systematically significantly higher or lower than the LRMC of the marginal new-entrant plant for such a capacity factor, it would be expected that significant entry or exit would occur until an equilibrium were reached.

Accordingly, this price-based approach is considered to be a reasonable estimate of the resource cost implications of losing (or indeed gaining) a MWh of hydro generation at different times of the day and year and for different hydro states – although probably a lower bound.

It is considered to be a lower bound because the shape of prices would likely change in the future in response to altered hydro generation outcomes. With so many moving parts and degrees of freedom, it is inherently difficult to forecast accurately the scale of such price changes. However, in general the likely nature of such price changes will mean that using a pre-change price array will probably under-estimate the scale of such cost impacts. For example if the altered hydro generation outcomes were to increase the differential between the amount of water available during dry years compared to wet years, it would be expected that the differential between dry and wet year prices would increase – and vice versa if the dry/wet year water differential were to decrease. However, costing such altered hydro generation outcomes at the pre-change price array will generally under-estimate the impact.

That said, it is not considered that such changes are likely to be of such a scale as to result in order-of-magnitude changes in the results. This is because:

- The fundamental drivers of new generation entry and exit for both baseload and peaking plant described above will still be a key factor determining the overall level and shape of prices. Such drivers will constrain the extent to which massive structural change in prices could occur.
- The scale of altered hydro electricity generation outcomes shown by the results is not considered to be of a magnitude that would fundamentally change the hydro-thermal nature of the New Zealand electricity market and the formation of its prices.

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undertaken by MBIE of generator new-build costs; and the forward curve for electricity as represented by ASX futures contracts.

31 In the late '90s the cheapest new baseload generator was considered to be a combined-cycle gas turbine, with an estimated LRMC of approximately $40/MWh. However, a significant increase in gas prices, coupled with the introduction of a cost of carbon, has meant that the cost of a new CCGT is estimated to have more than doubled since that time. Accordingly, the marginal new baseload generation is considered to be geothermal, with an LRMC of approximately $85/MWh.

- A simple analysis looking at extreme hydro generation and price changes for a simplified two period (high demand / low demand) two state (dry / wet) model suggests that the % error from estimating costs using a pre-change price array is unlikely to be large.

Lastly, it should be noted that this market price-based approach should also deliver reasonable estimates of lost generator revenue for their specific hydro schemes.

3.2 Residual non-hydro generation cost based approach

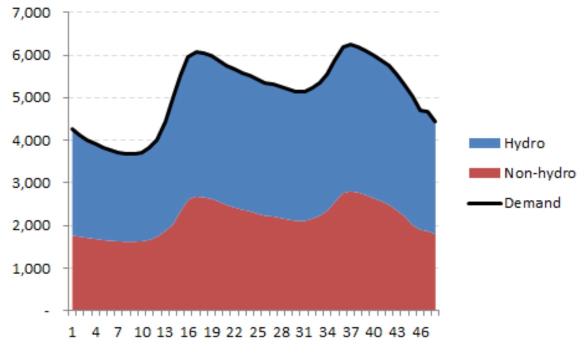
The second approach has been to estimate the likely impact of altered hydro generation profiles on the requirements for non-hydro plant – both in terms of altered operations (and hence altered fuel burn, CO_2 and other variable costs), and altered investment (and hence capital and fixed operating costs).

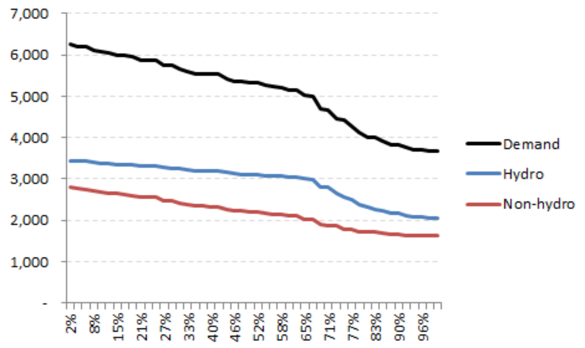
A simple approach has been undertaken to achieve this based on the concept of the 'residual demand' for non-hydro plant. This approach is as follows:

The modelling framework considers typical within-day profiles of demand and hydro generation for business days and non-business days for each of the four seasons, as well as distinguishing between five different hydro inflow states (Very Wet, Wet, Mean, Dry, Very Dry) based on national inflow sequences. Each hydro state is a quintile of the overall population of historical inflow series. A hydro state has been assigned to each historical season (i.e. Summer, Autumn, Winter, Spring) rather than a historical year. This is because, as set out above, New Zealand has limited seasonal hydro storage capability. Accordingly, dry and wet events are most significant when measured over a timescale of 3 to 5 months, rather than over a period of a year.

This combination of different demand and hydro generation profiles for the different days and hydro states are combined to produce a residual non-hydro demand duration curve.

The illustration below shows the concept of how a residual non-hydro demand duration curve is constructed:





As can be seen, because the hydro generation is sculpted into higher demand periods, the shape of the non-hydro residual demand duration curve is flatter. Appendix A provides more detail about the interaction of hydro generation and non-hydro generation.

A change in hydro generation for a particular scheme can be fed into this framework in order to estimate the change in the residual demand for non-hydro generation, and thus the impact of such altered hydro generation outcomes on the wider New Zealand system.

The cost of these altered requirements for non-hydro generation are calculated as follows:

- Changes in the amount of baseload non-hydro generation required are valued at the long-run marginal cost of such baseload generation – the central estimate of which is \$85/MWh. This applies both to increases *and* decreases in the amount of non-hydro baseload generation required. This is a long-run framework which assumes that demand growth will give rise to a requirement for new baseload generation to be built over the long-term. A reduction in the demand for non-hydro baseload generation (e.g. due to shifting hydro generation away from day periods towards night periods) will therefore give rise to a reduction in the amount of new baseload generation that would otherwise have needed to be built.

- Changes in the amount of non-hydro peaking generation required are valued as follows:
  - The carrying cost associated with requiring a greater amount of peaking capacity on the system is valued at $145/kW/yr. This is an estimate of the levelised capital and fixed operating & maintenance (O&M) costs associated with a new OCGT. Any changes in the requirement for baseload generation are taken into consideration in estimating the requirement for peaking capacity. For example, if altered hydro generation means that less non-hydro baseload generation is required, such baseload generation would not be available to contribute capacity at peak, therefore giving rise to an increase in the requirement for non-hydro peaking capacity than would otherwise have been the case.
  - The variable costs of increased GWh of peaking operation are based on the variable O&M plus fuel and CO_2 costs of such generation.
- Changes in the amount of non-hydro mid-merit generation are predominantly costed on a variable cost basis, being the average of the fuel and CO_2 costs of the existing gas-fired CCGTs and the coal-fired Huntly power station. No consideration is made of the capital or fixed operating costs of such existing plant as they are sunk / unavoidable. Any increase in the amount of capacity required for mid-merit generation is assumed to be met through building a new OCGT, rather than a new CCGT. The costs of such new mid-merit generation are calculated the same as for the costs of new OCGTs built for peaking purposes.

3.3 Potential impacts on consumer prices

The preceding sections focussed on the cost to New Zealand (i.e. economic efficiency impacts) that would be expected to arise if existing generation output or flexibility is lost.

There would also be an impact on electricity consumers, which differs from the economic efficiency cost. This difference arises because consumers would not only pay a higher price for any new generation that is required. They would also be likely to pay higher prices for other existing generation over time[32].

The key driver of this price increase is the fact that each successive new baseload generator that is built is likely to be slightly higher cost than the previous generator. This is due to the fact that each renewable generation project in New Zealand has different strengths and weaknesses (e.g. quality of renewable resource versus scale of engineering effort required to harness such resource) resulting in different costs for all of the different schemes[33].

Figure 13 below shows an estimate of the cost-supply curve for new baseload generation projects in New Zealand which is an estimate of the cost of the potential new baseload generation projects ranked in increasing order of price.

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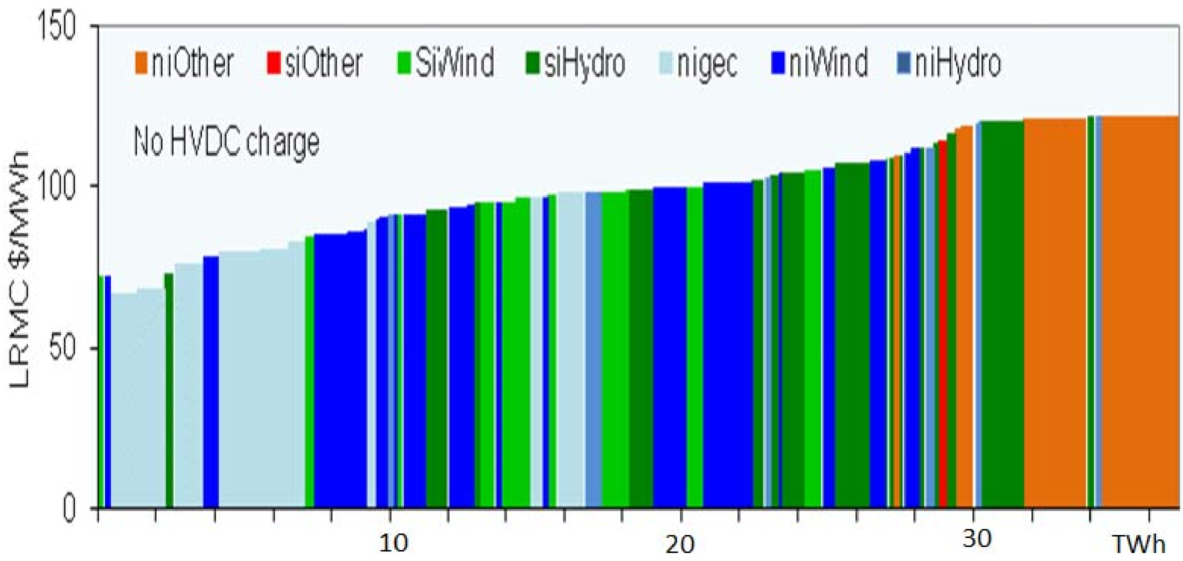
[32] This phenomenon is common to most goods and services in the economy. For example, if the cost of constructing new houses were to increase, this would be expected to feed through to the price of new houses *and existing* houses over time.

[33] This means that if all new generators cost exactly the same amount to build, there would be no price impact from the loss of any generation, as there would be no change to the prices required to cover the cost of replacement generation. There would, however, be an economic cost impact.

That said, it is possible in such a scenario that there could be some short-term price impact if the loss of generation were sudden and unanticipated, and the market had insufficient time to build new generation to restore the supply / demand balance into equilibrium.

Figure 13: Projected long run marginal cost of new base-load plant



Source: "Transmission Discussion Paper", Transmission Pricing Advisory Group, June 2011

The slope of this curve implies that for every GWh of new generation required to replace lost hydro generation, prices will rise by approximately $0.0018/MWh on average[34].

For a given GWh loss of generation from a scheme, this $0.0018/MWh needs to be multiplied across total annual electricity consumption of approximately 40,000 GWh to give the estimated $million increase in New Zealand's electricity bills.

It should be noted that this 0.0018 $/MWh/GWh slope is less than that calculated for an earlier analysis[35], which produced a value of 0.0027 $/MWh/GWh.

Given the uncertainties in estimating the relative cost of new generation projects, the value used in this study in order to estimate the impact on consumers' bills is an average of these two slope values.

[34] It should be noted that the electricity price consumers' face is not just driven by electricity wholesale prices, but also due to a number of other factors such as transmission and distribution charges, retail operating costs, and retail competition outcomes. It is not considered that changes in hydro generation would impact these other factors, and thus have been held constant for this analysis.

[35] This earlier analysis was "*Power Generation and Water in New Zealand*" published in July 2010. It used a cost-supply curve from an August 2009 MED report: "*Improving Electricity Market Performance, Volume 2*"

4 Results and conclusions

Nature of impacts on electricity system arising from altered minimum flows

The analysis in this study demonstrates that increasing the minimum flow requirements on rivers used for electricity generation will impose costs on the electricity system as measured by a number of potential metrics:

- Whole-of-New Zealand resources cost implications (i.e. the economic cost implications) arising from the need to replace lost hydro generation with non-hydro generation, thereby incurring the associated fuel, CO_2, capital and operating costs.
- Lost revenue to the owners of such electricity generation; and
- Increases to electricity consumer bills.

The principal focus of this study has been on the first bullet point – i.e. the economic cost implications – although the study does also address the likely implications for the other measures.

Such increased costs will primarily arise from two main phenomena:

- ***Reduced diversions***[36] into rivers used for electricity generation arising from increasing the minimum flow requirements in waterways from which water has been diverted.
- ***Loss of flexibility*** from reduced ability for hydro generators to store water at low value times for use at high value times. This loss of flexibility arises because generators:
  a) Will need to release more water at some low value times (generally times of lower demand) in order to meet increased minimum flow requirements at such times. This released water will therefore no longer be available for use at higher value times (generally times of higher demand); and
  b) Will need to hold more water back in their reservoirs to ensure they can meet increased minimum flow requirements if inflows over the subsequent days / weeks / months[37] turn out to be low – i.e. in case of a 'dry' inflow sequence. On average[38] this water will be held back during higher value periods than those during which it is subsequently released. Operating the reservoirs more conservatively in this fashion may also result in increased spill if subsequent inflows turn out to be very wet. This increased spill will result in less water being available for hydro generation at other times.

Such impacts can be summarised as:

- An absolute loss of hydro generation output across the year due to reduced diversions and increased spill; and

[36] In the parlance of fresh-water use, diverting water from one waterway into another for the purposes of electricity generation is known as a 'consumptive' use of water. This contrasts with generating electricity using water which hasn't been diverted which is known as a 'non-consumptive' use.

[37] Schemes with small reservoirs require storage and release decisions on the timescale of a few days, whereas schemes with very large reservoirs (e.g. the Waitaki scheme) require storage and release decisions on the timescale of 4-5 months.

[38] Due to the uncertainty over future inflows, it is possible that in some instances the altered pattern of hydro generation may turn out to be 'fortuitous'. However, on average it would be expected that generators would not be able to optimise their hydro storage and release decisions as well as they would otherwise have been able.

- A temporal shifting of hydro generation output between time periods. In general such shifting is away from higher value periods (i.e. peak demand periods on both a seasonal and diurnal basis) and to lower value periods.

Any absolute loss of hydro generation will need to be replaced by non-hydro generation which is more expensive. Given that the variable cost of the lost hydro generation is close to zero, the net cost of such replacement generation is likely to be significant.

Where hydro generation is time-shifted from periods of higher demand to periods of lower demand, the cost of replacing the hydro generation from the higher demand periods will be partially offset by displacing the cost of the non-hydro generation for the lower demand periods. However, given that the cost of non-hydro generation during higher demand periods is materially higher than during lower demand periods, the net cost impact will still be material.

Potential scale of impact on electricity system arising from altered minimum flows[39]

The following graphs set out the analysis which demonstrates the above phenomena, and which also emphasises how the scale of such impacts can vary significantly between schemes due to material differences in the characteristics of such schemes[40].

The figure below demonstrates the scale of electricity cost impact will vary significantly from river to river[41].

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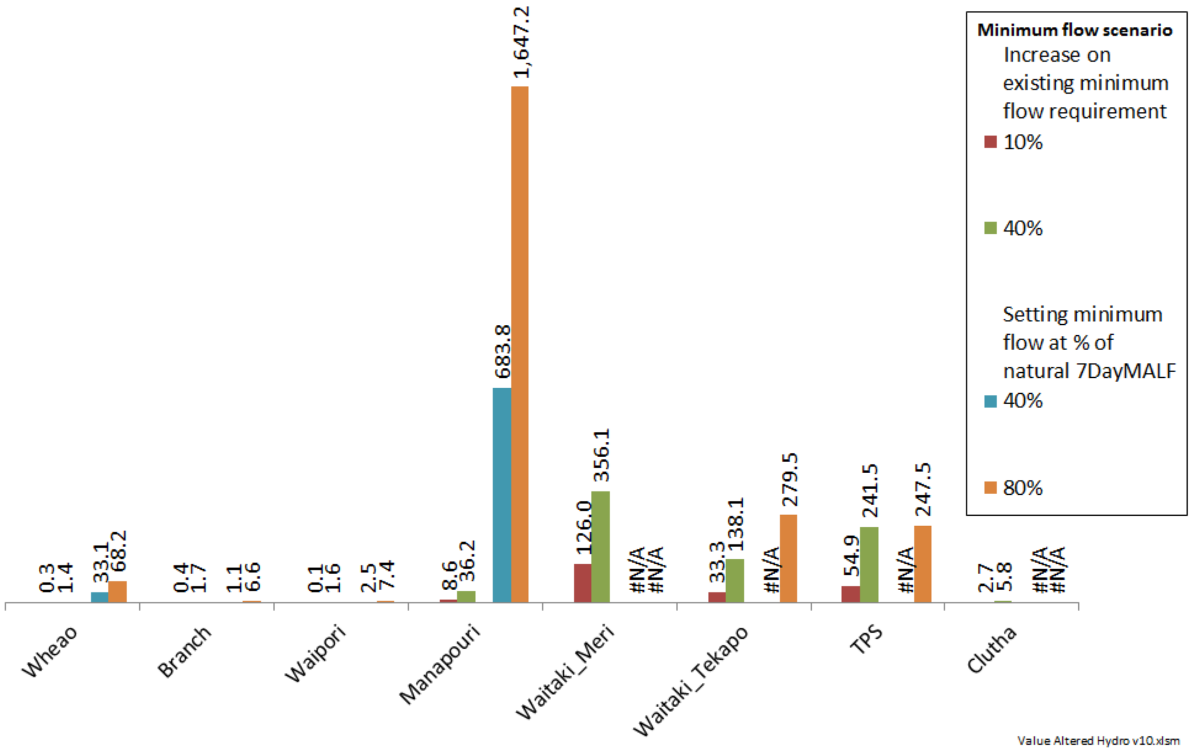
39 As set out in Appendix C, there was close alignment between the two different modelling approaches (market price-based and residual non-hydro cost-based) to estimating the economic cost impacts of altered hydro generation outcomes. Accordingly, the results presented in this section are based on the average of the two approaches.

40 It should be noted that generator analysis was not provided for some schemes and some scenarios. However, it is considered that a sufficiently large number of case-study schemes were provided, which span the range of scheme characteristics, in order to robustly demonstrate the potential nature and scale of altered minimum flow regimes on rivers used for electricity generation.

41 The metric for demonstrating cost impacts is the Net Present Value of the electricity system costs measured over 25 years using an 8% discount rate. This metric was chosen as it is considered to best represent the long-lasting system consequences of altering hydro-generation capabilities.

Figure 14: Estimated scale of impact on electricity system costs for different hydro schemes and minimum flow increases (25 yr $m NPV cost)[42] [43]



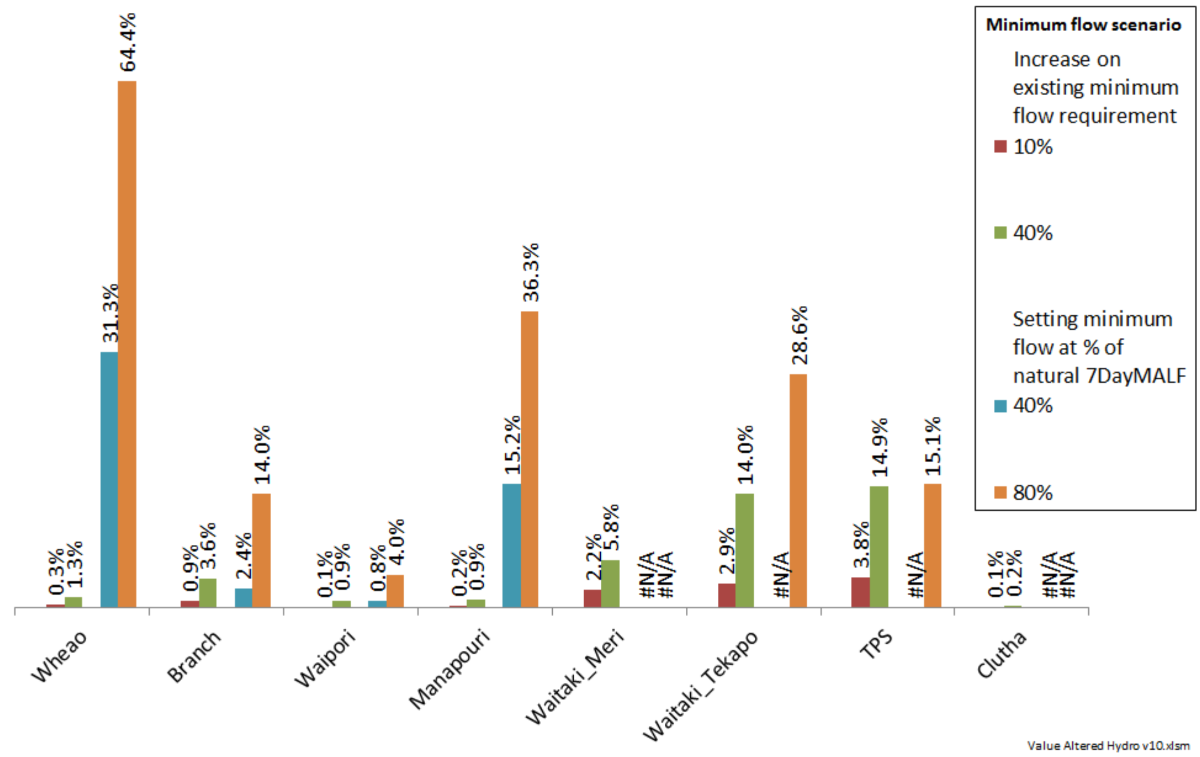
Some of this variation in cost impact arises from simple variation in the size of river and associated hydro scheme.

42 Because the Waitaki scheme has been split between Genesis Energy (which owns the Tekapo stations) and Meridian, (which owns the rest) the analysis has distinguished between these two as Waitaki_Tekapo and Waitaki_Meri, respectively. '7DayMALF' stands for seven day mean annual low flow, and is a measure of the minimum flow levels that occur naturally in the river.

43 Meridian provided information as this report was being finalised which suggested that their earlier modelling of the Waitaki (which formed the basis of the results in this report) probably under-estimated the scale of impact by approximately 10%. However, there was insufficient time to incorporate such updated analysis into the final report.

However, when looking at the cost impacts as a proportion of the total value of the scheme, it can be seen that the proportional impact varies significantly between different schemes and scenarios. This is indicated in the following figure.

Figure 15: Cost impact of altered minimum flows represented as a proportion of a scheme's total value

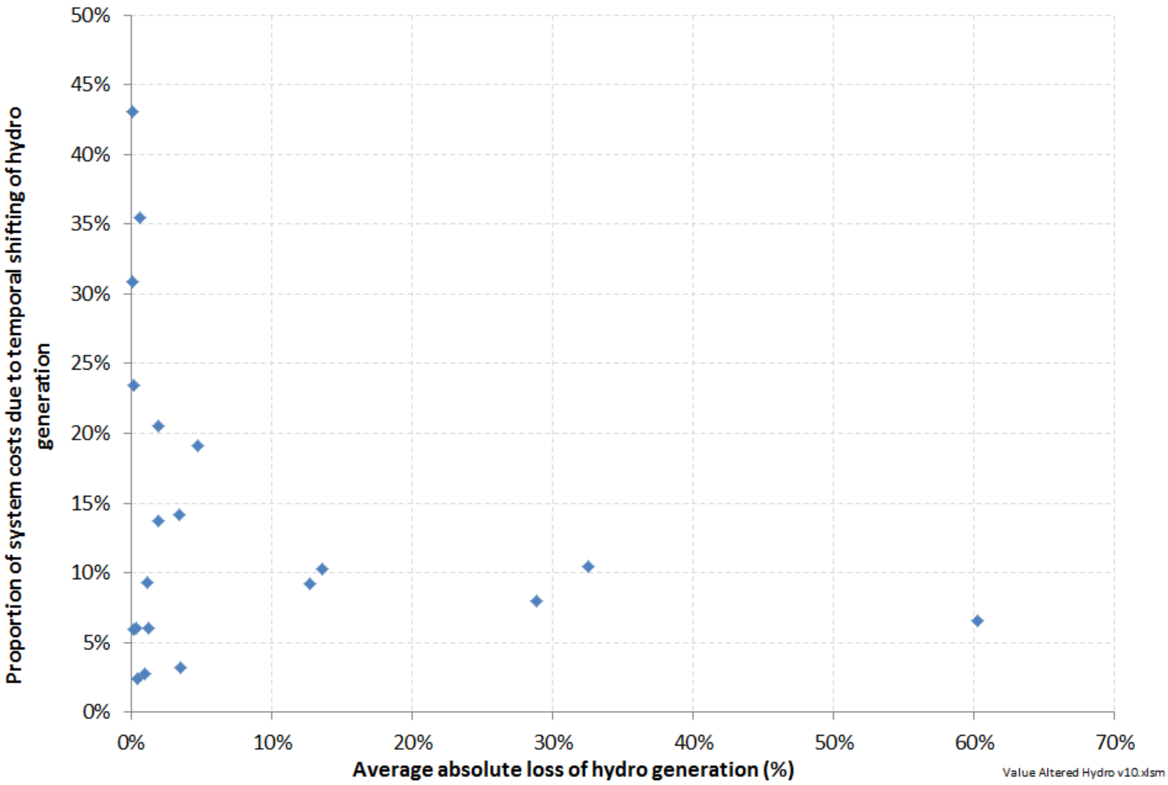


This significant variation between schemes in the nature and scale of impacts arising from altered minimum flow scenarios are driven by a number of key factors which vary significantly between schemes:

Firstly, whether the increased minimum flow results in reduced diversions into a river, or reduced flexibility within a river. The cost consequences of losing water from diversions into a river are generally much greater than reduced flexibility within a river[44]. This is illustrated in Figure 16 below.

44 In this respect, it is worth noting that the high costs attributed to the Waitaki scheme are in large part due to reduced diversions 'within' the scheme – thus currently water is diverted out of the Tekapo and Pukaki rivers and fed into the generating stations at the top half of the Waitaki chain. Increasing the minimum flows in the Tekapo and Pukaki rivers would therefore result in a lot of water bypassing the generating stations in the top half of the scheme If only the minimum flows at the bottom of the chain were increased (i.e. for the lower Waitaki, but not for the Tekapo or Pukaki rivers), the scale of losses would be significantly less.

Figure 16: Estimate of the proportion of costs arising from the temporal shifting of hydro generation from higher demand periods to lower demand periods compared to the loss of absolute GWh of generation[45]



As can be seen, even where relatively little absolute generation is lost, the cost impacts from the temporal shifting of hydro generation from higher demand periods to lower demand periods are still less than 50% of the overall system costs.

The second factor driving the difference in impacts between schemes is how the current level of consented minimum flows applying to a river compare with natural minimum flows. Thus,

- If a river currently has a low consented minimum flow relative to natural minimum flows, a 10% increase on such a low minimum flow level will have a relatively small impact compared to a 10% increase on a minimum flow which is much larger compared to natural minimum flows.
- However, if a scheme is already operating to a minimum flow which is close to (or even above) natural minimum flow levels, it may not be physically possible to increase minimum flows further above such natural levels unless the scheme has significant amounts of seasonal storage[46].

45 This estimate was calculated for a given scheme by calculating the system costs from a revised generation profile which had the same absolute loss of GWh of generation as the post-change generation profile calculated by the generators, but the same pre-change generation profile 'shape'. The difference between this cost estimate, and the cost estimate for the post-change generation profile calculated by the generators can then be ascribed to the altered shape of generation.

46 For example, the lack of significant seasonal storage for the Clutha scheme means it would be unable to materially increase consented minimum flows at the bottom of the scheme as they are already above natural minimum flow levels. Similarly, the modelling suggests that it would not be feasible to increase minimum flows in the Waikato scheme beyond a certain point without resulting in breaching Taupo minimum lake levels during dry years. This would be exacerbated if increased minimum flows for the TPS diversions reduced the amount of water flowing into

The third factor driving the difference in impacts between schemes is the difference in the MWh/cumec conversion ratio for different rivers. Thus:

- the design of some hydro generators means they are able to generate significantly more electricity per cumec of water than other hydro generators.
- some hydro schemes are comprised of a chain of generators along a river meaning that a cumec of water will be used for electricity generation many times along that chain.

This difference in MWh/cumec conversion factors means that the loss of a cumec of water can have very different electricity system impacts depending on where it is lost from. For example, reduced diversions feeding into the top of the Tongariro Power Scheme (TPS) (which subsequently feeds into the Waikato scheme) would result in the loss of approximately 4.5 times more generation than the same quantity of water lost through reduced diversions into the Manapouri scheme.

The fourth factor driving the difference in impacts between schemes is the difference in the general seasonal timing of inflows for a scheme and whether they are generally naturally correlated with demand (e.g. Waikato) or not (e.g. Waitaki). Generally, if seasonal inflows are correlated with demand it is likely that there will be a greater cost impact on seasonal storage and release decisions than if inflows are anti-correlated with demand[47].

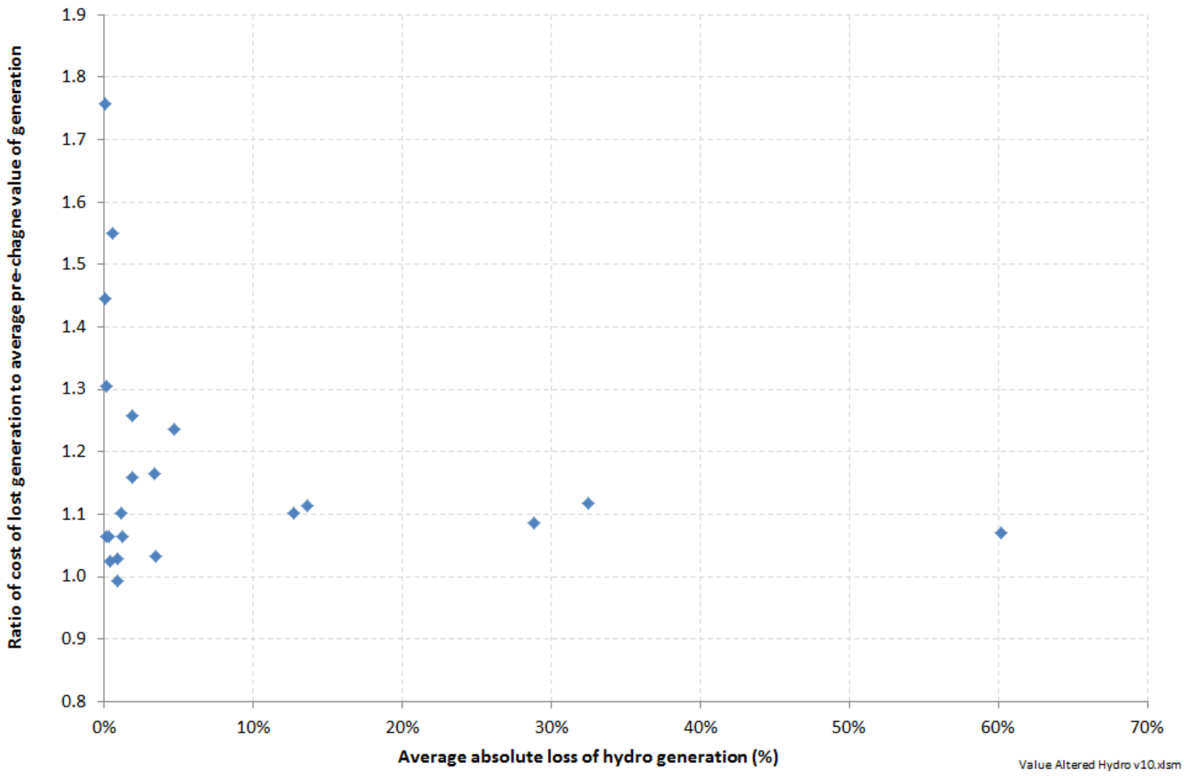
The last factor driving the difference in impacts between schemes is the difference in the extent of storage reservoirs on the river, and thus the ability to manage flexibility impacts. The nature of this impact is very scheme specific, and varies in a non-linear fashion with respect to increasing minimum flows within a scheme. These different flexibility impacts results in significant differences in the types of altered non-hydro generation outcomes in terms of changes to baseload, mid-merit and peaking non-hydro plant.

Given the significant variation in all of the above, it is hard to generalise about the cost impacts. However, where increased minimum flows results in significant loss of generation (particularly through reduced diversions), modelling indicates that the $/MWh value of this lost generation is likely to be approximately 10% - 20% greater than the average $/MWh value of the scheme's generation prior to the change. This is indicated by the following figure.

Taupo. These physical constraints have meant that it has not been possible to model increased minimum flows for the bottom of the Clutha at all, or the Waikato above a certain level as it becomes infeasible.

47 Increased minimum flow requirements require hydro generators to hold more water in storage to manage potential future low inflow periods. If such low inflow periods are most likely to occur over summer, this will require the hydro generator to hold more water back during the winter and spring. However, the winter and (to a lesser extent) spring periods are when demand is greatest and generation is at its most valuable.

Figure 17: Plot of ratios of cost of lost generation to average pre-change value of generation[48]



As can be seen, as indicated by ratios greater than 1, the cost per MWh of this lost generation is almost[49] invariably greater than the average value of electricity from the scheme prior to such changes. This reflects the fact that increased minimum flows reduces the flexibility of hydro generators to store water at low value times for use at high value times.

48 This analysis attempts to 'normalise' the cost impacts for different sized schemes. This was done by calculating the $ cost of the altered hydro generation (i.e. due to reduced diversions and reduced flexibility) and dividing by the MWh of lost generation. This $/MWh value was then compared as a ratio with the average $/MWh value of the scheme's generation before the change in minimum flow.

49 There are a couple of data points which indicate that the average cost of the lost generation was less than the average pre-change value of the generation. It is suspected that these are the result of inaccuracies in modelling of the altered generation outcomes as such a result would indicate that the loss of generation would enable the scheme to improve the optimisation of its water.

Cumulative effects of multiple rivers facing increased minimum flows

It should be noted that the cost estimates produced in this analysis are based on evaluations of individual schemes in isolation. Simply summing the costs for each of the individual schemes to estimate a total New Zealand cost if all schemes were to have their minimum flows increased by the same amount would not be appropriate for two reasons:

1) It is understood that there is absolutely no policy driver for considering such a "one-size-fits-all" approach for minimum flows on rivers[50]; and

2) Altered hydro generation outcomes for one scheme will affect the storage and release decisions for other hydro generators. Accordingly, a 'true' estimation of these cumulative cost impacts would require more sophisticated whole of New Zealand hydro modelling than has been undertaken by the generators individually. That said, initial analysis suggests that the cumulative $m impact of several schemes having altered minimum flow regimes is unlikely to be radically different to summing the individual $m impact of each scheme – although potentially a lower bound.

Impact on consumers' bills

The principal focus of this study has been to consider the economic cost impacts on New Zealand – i.e. estimating the cost of altered fuel burn, other operating costs, and capital investment requirements. However, it is also the case that altered hydro generation outcomes could impact on consumers' bills through higher consumer prices. Such an outcome could arise if the loss of any hydro generation requires the building of progressively more expensive replacement generators[51]. In other words:

- if each new generator costs more to build than the last, there would likely be a consumer price impact in addition to the economic cost impact; whereas
- if each new generator costs the same to build as the last, there would only be an economic cost impact, but no consumer price impact[52].

Analysis indicates that New Zealand does face an upward sloping new generation cost-supply curve as there is considerable variation in the cost of New Zealand's new generation options – particularly driven by variations in the characteristics of the different new renewable generation options. The slope of this cost-supply curve suggests that the $m magnitude of an increase in all New Zealand

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[50] Officials have advised that the policy as noted in the discussion document is that:
- Regional Councils will continue to make decisions about freshwater management in their region.
- The proposed policy is to introduce environmental bottom lines and a national objectives framework
- In order to meet these objectives, Regional Councils *may* decide to implement minimum flows across some of their catchments. These decisions would take time and involve significant community engagement.

In other words, Regional Councils will continue to decide on arrangements for rivers within their region, and the purpose of this study is to understand what the broad impact might be *if* Regional Councils decided to implement minimum flows.

[51] This is based on analysis of price impacts in the long-run using a framework whereby prices, over-time, must be equivalent to the long-run marginal cost of new generation supply. If prices do not reach such a level over time, it would be expected that there would be insufficient new generation built to meet demand growth.

[52] This outcome arises due to the fact that prices, in the long-run, will need to be at a level equal to the long-run marginal cost of the marginal source of new supply. If there is no difference in the cost of different sources of supply (i.e. there is a flat supply curve), then there will be no change in price associated with differences in where the demand curve intersects with the supply curve. However, if new supply gets progressively more expensive (i.e. an upward sloping supply curve) then prices will be higher if the demand curve intersects a higher point on the supply curve.

consumers' bills will be very similar to the $m magnitude of the economic cost impacts shown in Figure 1 above[53], with the scale of impact depending on which hydro schemes face altered minimum flows and by how much.

Thus, the impact on consumer bills of a 40% increase in minimum flows for the Wheao scheme will be relatively insignificant (approximately a 0.002% increase on domestic consumers' bills), whereas for the Waitaki scheme the impact of a 40% increase in minimum flows would start to become more material (approximately a 0.35% increase on domestic consumers' bills). It is considered that the cumulative impact on consumers' bills of several schemes facing altered minimum flows would be additive rather than multiplicative[54].

Such a price effect would also result in an aggregate wealth transfer to generators, and a net gain to those generators not directly affected by the loss of generation.

Transitional impacts

The cost estimates set out above are based on the altered resource cost implications once the market has shifted to a new supply-demand equilibrium.

However, immediately following any change to altered minimum flow regimes the market may be in a situation of dis-equilibrium which could give rise to different cost outcomes – at least until demand growth and generation new-build / retirement transitions the market to a situation of supply-demand equilibrium again.

It is very difficult to assess the likely nature and scale of such short-term impacts as they are heavily dependent on:

- whether the cycle of new-build and retirement means the market is in a situation of over- or under-supply when such changes occur; and
- how much advance notice is given of a change in minimum flows, and thus the extent to which such information can be factored into new-build / retirement decisions ahead of time.

Despite these inherent uncertainties, in general it would be expected that these short-term impacts would result in higher $/MWh costs than the long-term costs as the market would move into a situation of relative scarcity.

Other impacts

The principal focus of this study has been on electricity cost impacts arising from altered hydro generation outcomes. However, it should be recognised that there would likely be other impacts from such altered generation outcomes including:

- potential increased risk of flooding in some areas;
- reduced amenity benefits for some water bodies;
- adverse environmental outcomes from an increase in non-hydro generation;
- potential negative environmental outcomes associated with altered river and lake levels; and

[53] This similarity between $m consumer bill impacts and $m economic cost impacts is purely a coincidence of the slope of the new-entrant cost-supply curve, rather than being driven by any inherent feature of markets which would give rise to such a relationship.

[54] It should be noted that the electricity price consumers' face is not just driven by electricity wholesale prices, but also due to a number of other factors such as transmission and distribution charges, retail operating costs, and retail competition outcomes. It is not considered that changes in hydro generation would impact these other factors, and thus have been held constant for this analysis.

- reduced ability to meet other policy objectives such as 90% renewable electricity by 2025.

It is beyond the scope of this exercise to evaluate the nature and scale of such potential impacts.

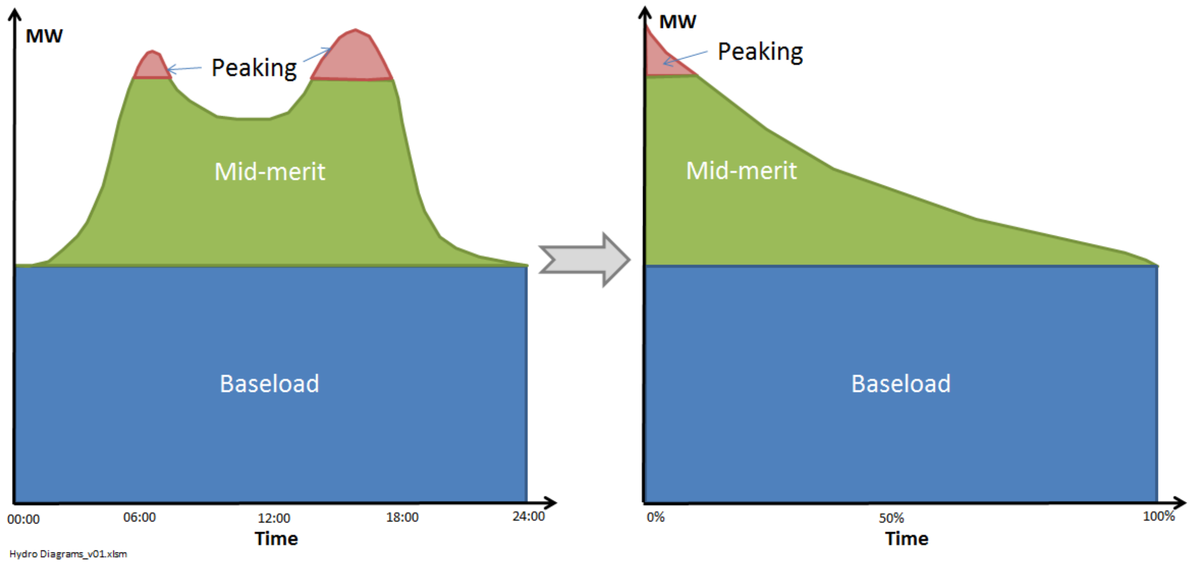
Appendix A. Introduction to the dynamics of hydro-thermal power systems

Electricity is an unusual product in that supply and demand must be exactly matched for every minute of every day. Further, it can't be economically stored in large quantities.

These facts, coupled with the fact that there is significant diurnal and seasonal variation in demand, mean that there is a requirement for some generation to operate all the time, and some generation to only operate for some of the time.

A typical categorisation for these different modes of operation is to classify those plant which operate all the time as 'baseload', and those plant which only operate for very infrequent periods of peak demand as 'peaking', with the intermediate modes of operation classed as 'mid-merit'. This is illustrated in the following diagram.

Figure 18: Illustration of the distinction between baseload, mid-merit and peaking plant



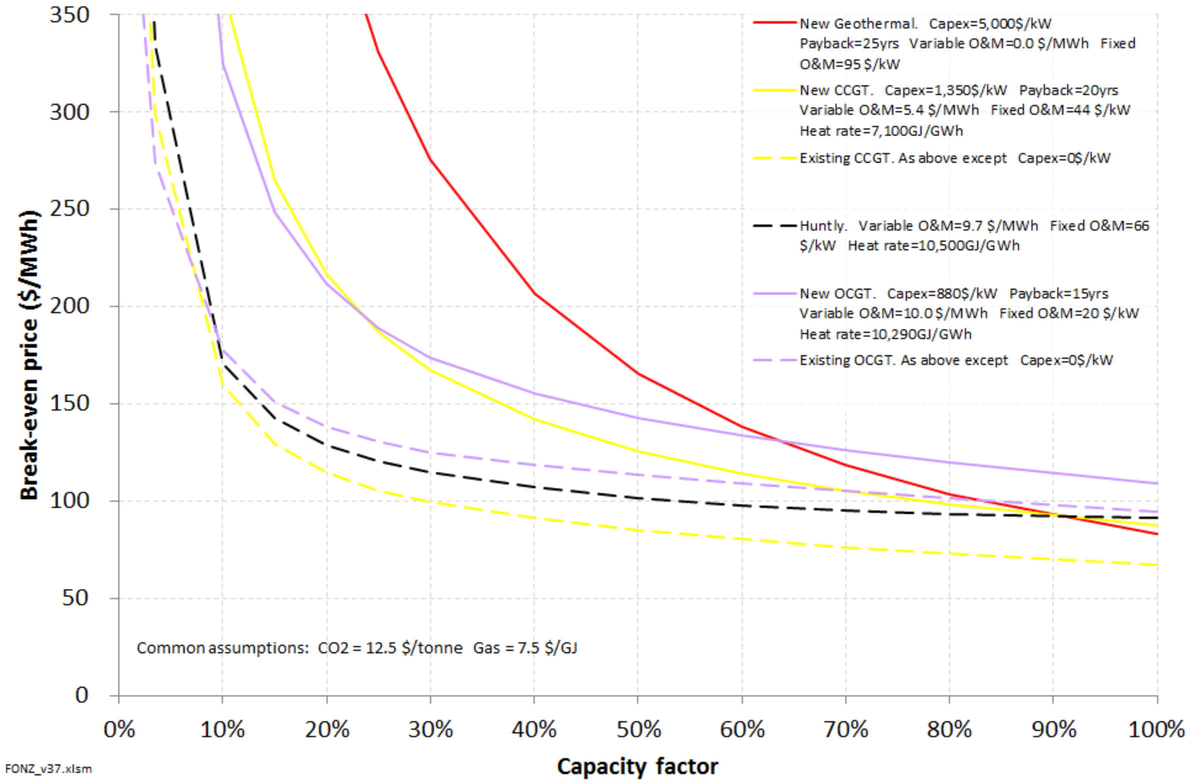
This approach to classifying these different modes of operation is useful because different types of electricity generator have different cost and performance characteristics which make them more or less suited to such modes of operation. In this respect, the capital intensity of the different types of generator has a significant bearing on their relative suitability for such duties.

For example, currently the most cost-effective new generation options in New Zealand for baseload power generation are geothermal power stations. These are very capital intensive (approx. $5,000/kW), but have very low running costs as the 'fuel' is free. For baseload operations, the long-run marginal cost (LRMC) of production from such stations is estimated to be approximately $80-85/MWh. This cost includes a capital recovery element whereby the capital cost of the power station is spread over the expected GWh generated by the station over its lifetime.

However, if such a power station were built to only provide peaking power, the capital cost of the station would need to be recovered from a much smaller quantity of GWh. For example, if a geothermal power station whose LRMC was $80/MWh for baseload operation were instead to operate for only 10% of the time as a peaker, its LRMC would rise to $800/MWh.

It is for this reason why peaking requirements are typically satisfied by open-cycle gas turbines (OCGTs). Because of fuel and CO_2 costs, these generally have much higher *variable* costs than baseload renewable generators. However, because their capital costs are much lower – approximately one fifth of the cost of a geothermal generator – the capital recovery component of their costs is much less than for a baseload renewable generator. Thus, although their levelised costs of operation to provide peaking generation are high (e.g. approximately $250/MWh for a peaker operating at a 10% capacity factor), they are much cheaper than a geothermal generator for providing peaking power.

This is illustrated by the following diagram:



The key points to take-away from this diagram are:

- It is generally not cost-effective to build new plant to displace existing plant. As such, new baseload plant will generally only be built if baseload demand increases.
- Baseload renewables become particularly expensive if operate at low capacity factors.
- If there is a need to have new low capacity factor plant, it will be most cost-effective build new peakers (typically OCGTs), but only if it is not possible to run existing thermal plant harder – i.e. there is a capacity shortfall.

In summary, the characteristics of electricity are such that it costs significantly more to provide peaking power, than it does to provide baseload power.

While the above framework is reasonable to consider most ‘thermal’ power systems around the world (i.e. power systems which are dominated by thermal power generators), it is incomplete for consideration of power systems with a significant amount of hydro power.

This is for two reasons:

1) The ability for hydro generators with storage capabilities to ‘sculpt’ their water towards periods of higher demand; and

2) The year-to-year variation in inflows associated with variations in the weather.

Both factors are outlined further below.

Consideration of the impact of hydro storage

With respect to the first point, hydro generators with storage lakes can choose to store and release their water in such a fashion as to target their generation at periods of highest demand. For some hydro schemes the size of storage is relatively small such that their storage and release decisions are limited to within-day or within-week decisions. Typically such schemes will aim to target their generation towards periods of highest demand within the day – i.e. morning and evening peaks – and away from periods of lowest demand – i.e. overnight.

Other hydro generators have much greater storage capabilities, and can additionally seek to sculpt the release of their water on a seasonal basis – i.e. away from the lower demand summer months, and towards the higher demand winter months. As set out in the main body of the report there is significant variation in the ability of the different hydro schemes in New Zealand to perform such seasonal sculpting. The South Island Waitaki scheme has the majority of such seasonal storage capabilities, while the remaining hydro schemes are much less able to store water from one season to the next.

The ability of hydro generators to use storage to sculpt their water to meet variations in demand is illustrated in the following diagrams based on historical generation in New Zealand.

Figure 19 - Typical Summer Day

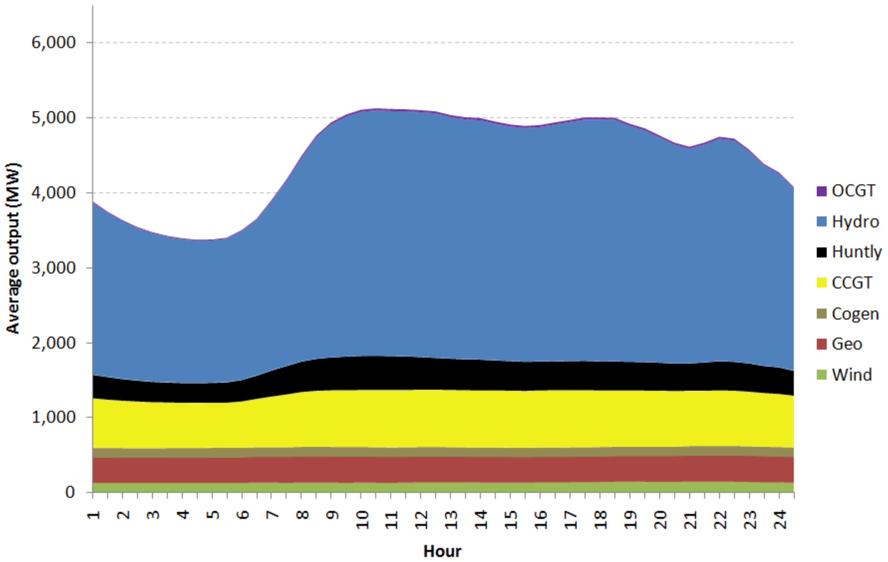
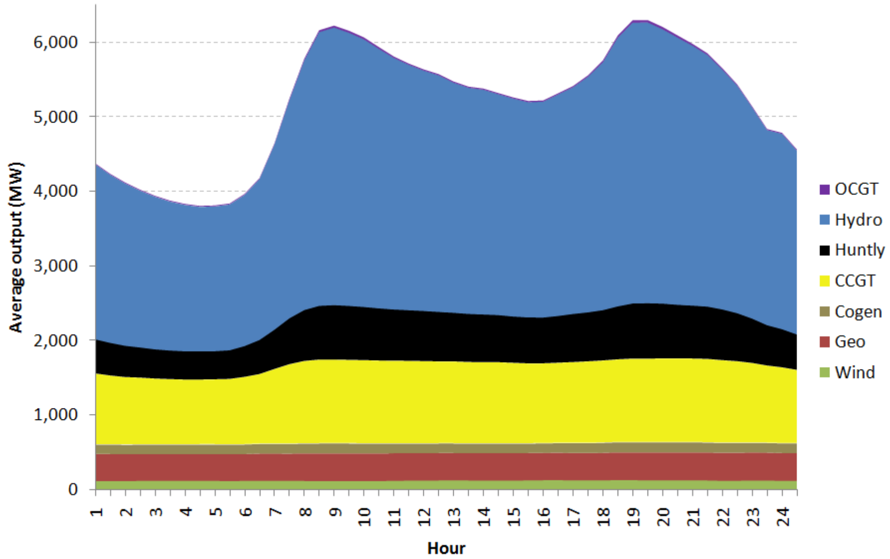


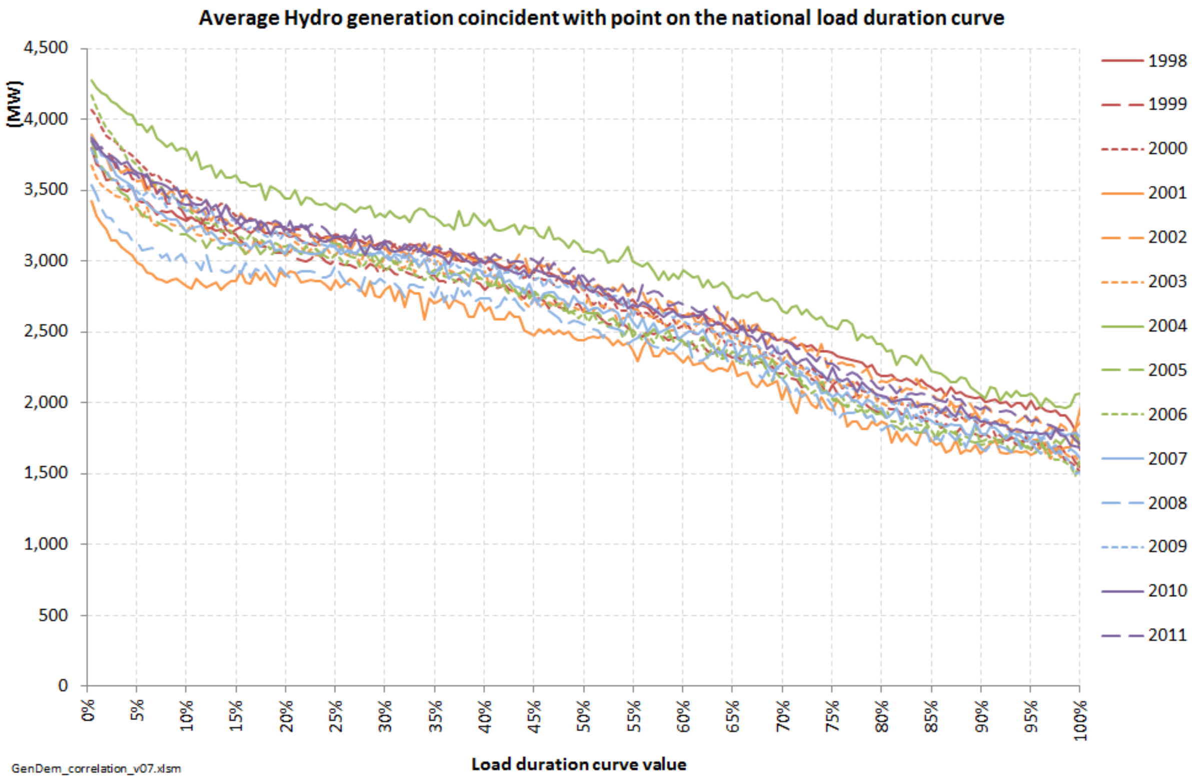
Figure 20 - Typical Winter Day



This ability of hydro generators to sculpt their water to match demand variations means that there is reduced variation in the *residual* demand for non-hydro generation. In particular, it means that such residual demand has a 'flatter' shape – i.e. there is not as great a requirement for higher cost peaking generation than there would otherwise be.

Consideration of variations in hydro inflows

With respect to the weather-driven year-to-year variation in hydro inflows, this has an effect which counter-acts the flattening in the residual demand for non-hydro generation. Thus, the increase in hydro generation in wet years will reduced the demand for non-hydro generation, and vice versa for dry years. This year-to-year variation is illustrated in the following diagram which shows how hydro generation in wet years (e.g. 2004) has been significantly greater than during dry-years (e.g. 2001).



The scale of this hydro variation is significant. Based purely on inflows, the scale of variation is of the order of 10,000 GWh between the wettest and the driest years. However, for some of the most extreme wet sequences, a significant proportion of the inflows will be lost as spill. Accordingly, the variation in usable hydro generation is closer to 7,000 GWh.

Overall impact on the residual demand for non-hydro generation

The following figures show how the seasonal and diurnal variation in demand, coupled with the variation in hydro generation, has impacted on the residual demand for non-hydro generation.

Figure 21: National demand duration curve (MW)

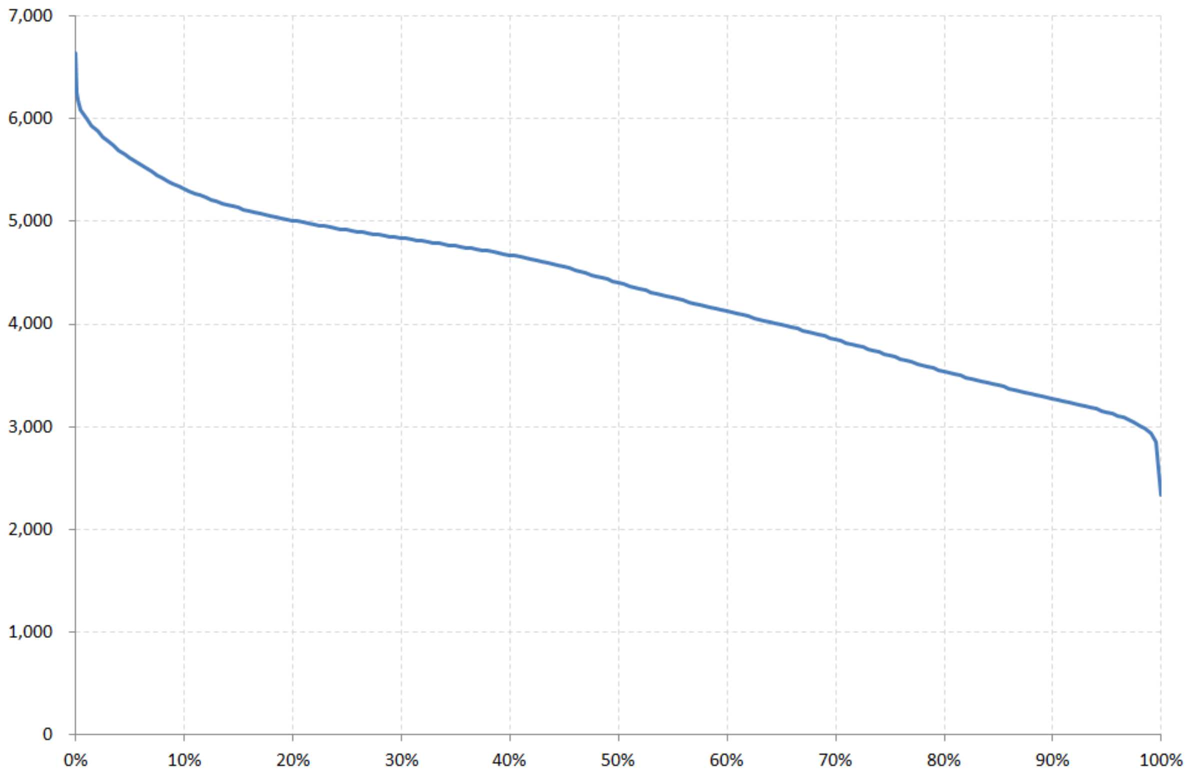
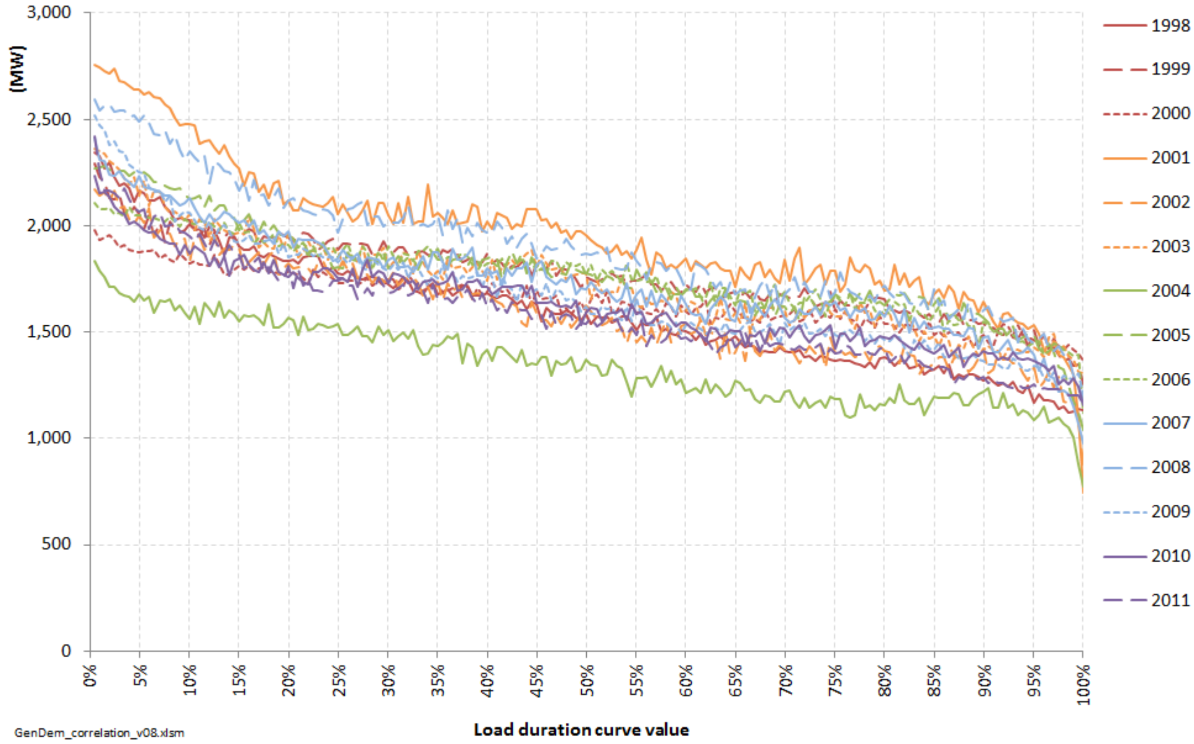


Figure 22: Historical pattern of residual demand for non-hydro generation coincident with point on the national load duration curve[55]

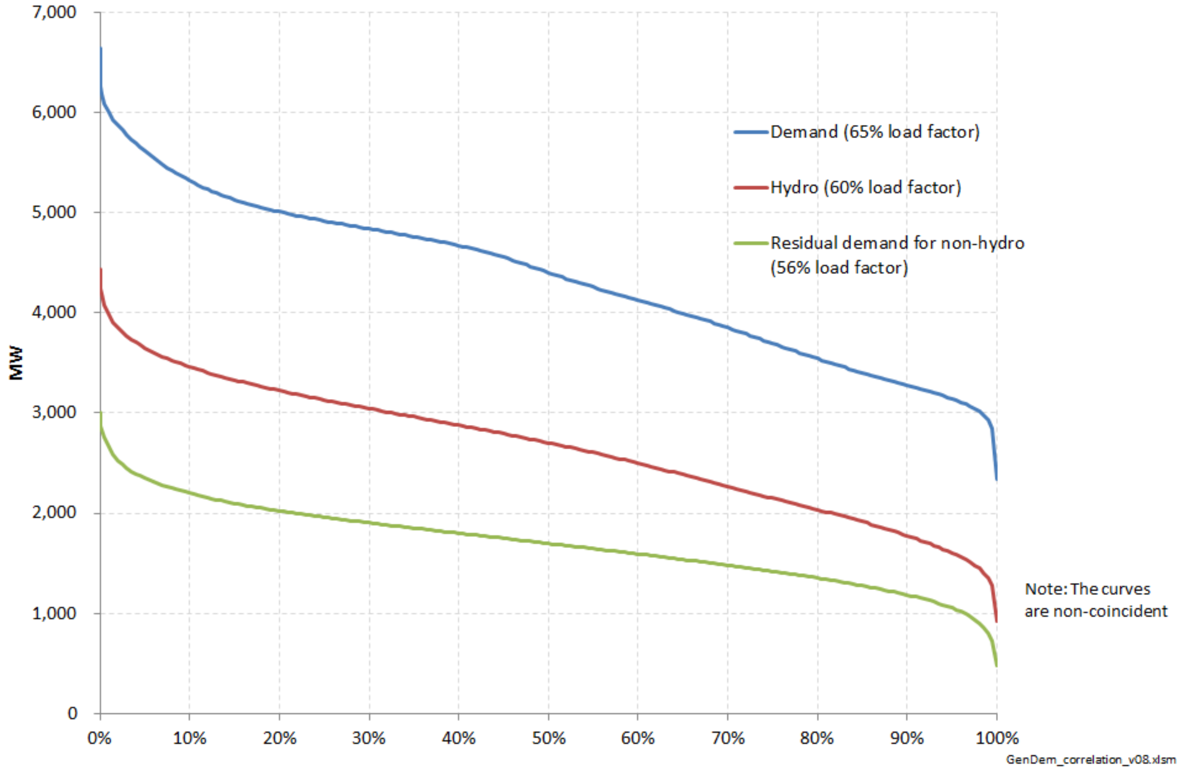


As can be seen, the within-year shape of residual non-hydro demand is flatter than that for demand overall, due to the within-year sculpting of hydro generation. However, the year-to-year variation in hydro generation has introduced significant year-to-year variation in the demand for non-hydro plant.

This is also illustrated in the following figure which shows the overall duration curves for demand, hydro and the residual demand curve for non-hydro generation for the period 1998 to 2011.

55 Note: This analysis takes account of the fact that there has been demand growth during the period 1998 to 2011, by 'normalising' demand to 2011 values by increasing demand in the previous years based on observed average annual demand growth.

Figure 23: Duration curves for national demand, Hydro and the residual demand for non-hydro generation for the period 1998 to 2011[56]



[56] Note: This analysis takes account of the fact that there has been demand growth during the period 1998 to 2011.

Appendix B. Key operational issues for hydro generators with storage

A key decision for hydro generators is when to store water in the reservoir, and when to release it for generation purposes. Storing water creates an opportunity to use it later, when it may be more valuable (e.g. to meet peak winter demand). On the other hand, if water is held back in storage and a significant rainfall (inflow) event occurs, the storage reservoir may become full. Conversely, using the water in the current period reduces the likelihood of spill, but may result in lost opportunities or increased costs in the future[57].

In this situation, there is no ability to control the rate of downstream water releases, and some water is more likely to be wasted as 'hydro spill'. This refers to a situation where water flows exceed the generation capacity of a power station on the river, and water must be spilled past the turbines without generating power.

This uncertainty over future inflows complicates a hydro generator's decisions over whether to use water now, or store it for later use.

Hydro generators also need to take account of resource management consent limits in their decisions. For example, they may need to ensure that:

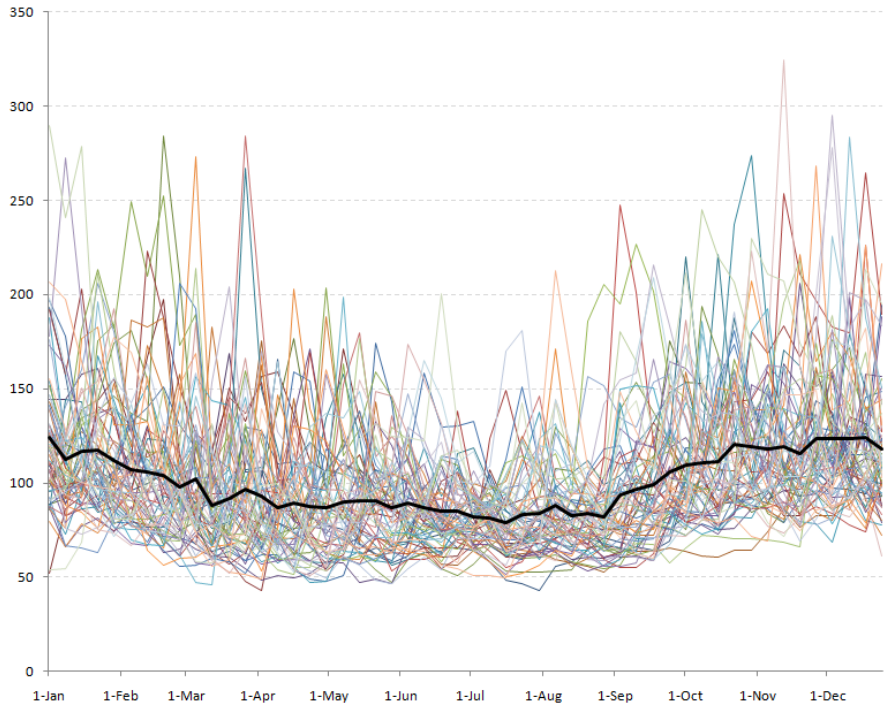
- water flows at various points along the river don't go below certain minimum levels;
- lake levels don't go below or above certain minimum or maximum levels; and
- in some cases, the rate of change of river levels doesn't breach certain limits.

These consent conditions can have significant impacts on the flexibility of hydro generation and the extent to which water use and hydro generation can be targeted at high value periods. A worked example has been put together to illustrate this point.

[57] For example if the generator runs short of hydro production and needs to purchase from the wholesale spot market to meet its contractual commitments.

Figure 24 shows a series of historical weekly inflows into a hypothetical hydro scheme[58].

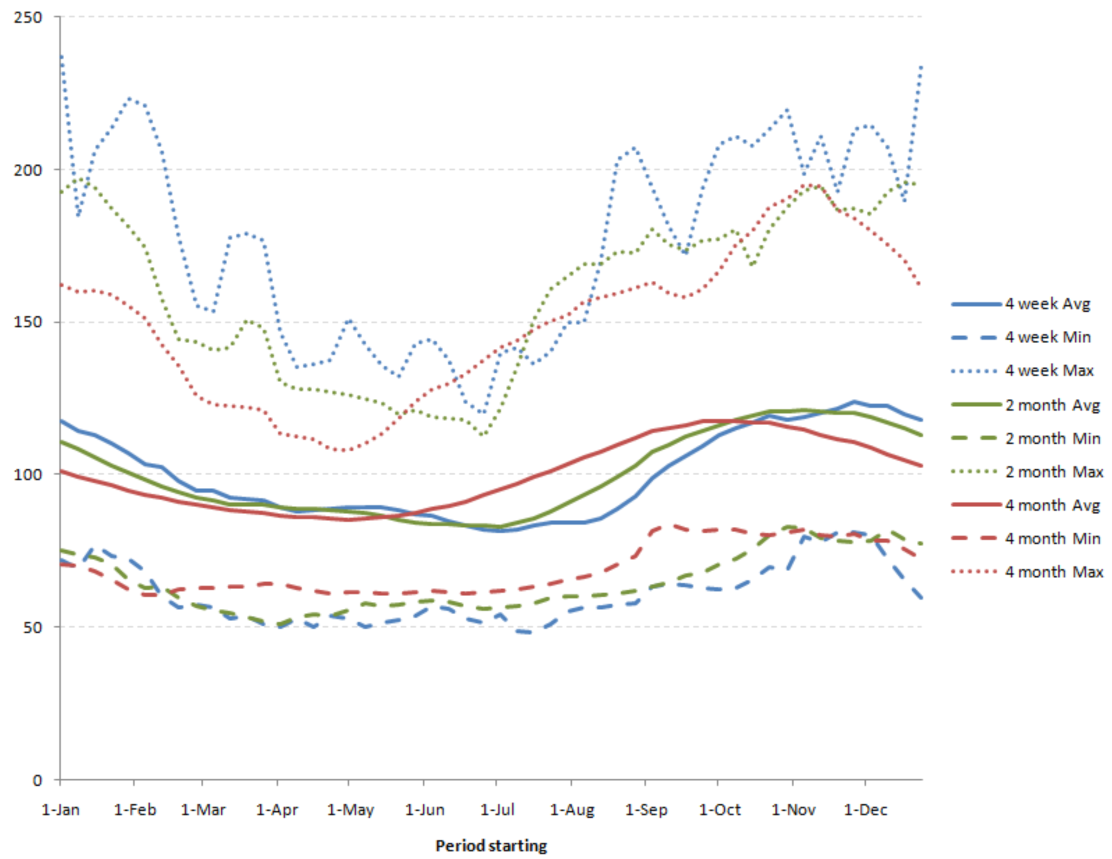
Figure 24: Hydro inflows



Not only is there significant weekly variation, but as Figure 25 below illustrates, there is also considerable variation in the minimum and maximum level of average weekly inflows *sustained* over several consecutive weeks or months.

[58] The inflows are based on those into the Waitaki from 1931 to 2001, but normalised to give an average value of 100.

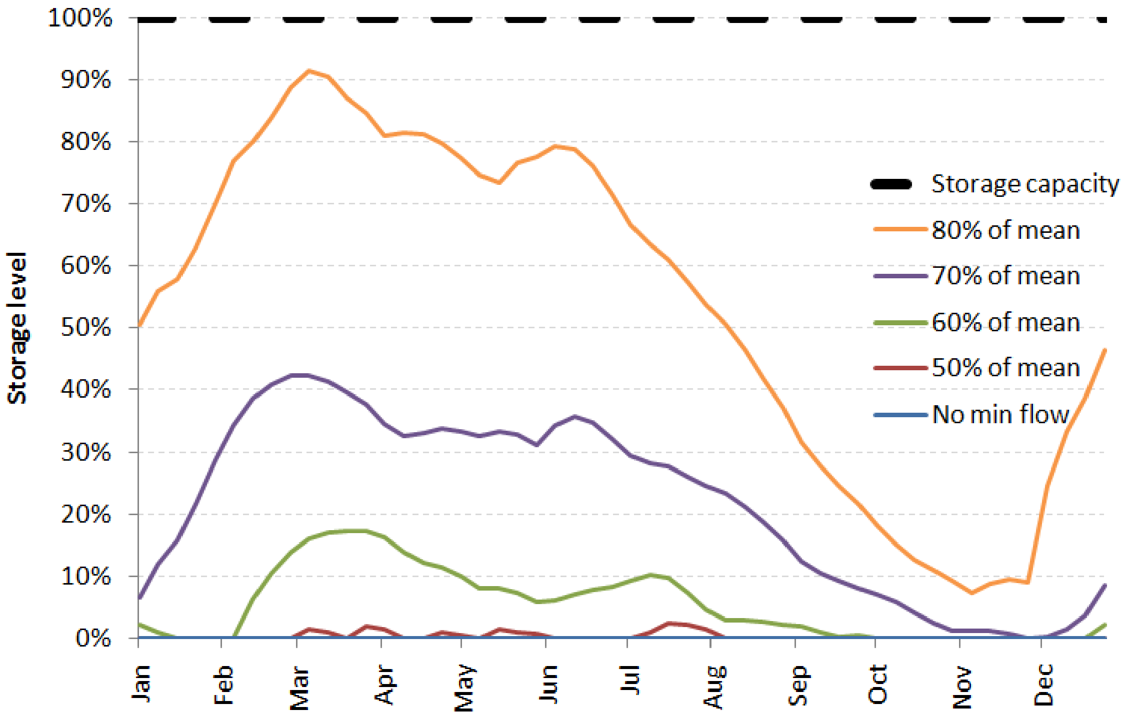
Figure 25: Average inflows over 4 week, 2 month and 4 month periods (cumecs/week)



One of the key factors determining the store or release decision for the generator operating in this catchment is the minimum flow requirements for the river downstream of the scheme. In particular, the minimum flow level will dictate a minimum reservoir storage level the generator must hold at varying points in the year.

At any given point in time, the amount of storage held in the reservoir must be sufficient to enable sustained release of water to meet minimum flow requirements should a worst-case sustained dry period occur. Hydro generators will typically base their decisions on historic inflow sequences. Because there is typically a seasonal trend to inflow sequences, the minimum storage level will consequentially vary throughout the year. Figure 26 shows the minimum hydro storage level that would be required to meet different downstream minimum flow levels for the above series of inflows.

Figure 26: Minimum storage required to meet different minimum flow limits



Clearly, increasing the minimum flow limit has the effect of raising the minimum hydro storage level needed at any point in the year to satisfy the flow requirement[59]. Put another way, increasing the downstream minimum flow level means the generator must hold back more water in storage to ride through the worst historic inflow sequence, all other things being equal.

While holding back more water in storage allows the minimum flow to be met, it reduces the useful operating range of the storage reservoir[60]. This in turn will result in less efficient use of water.

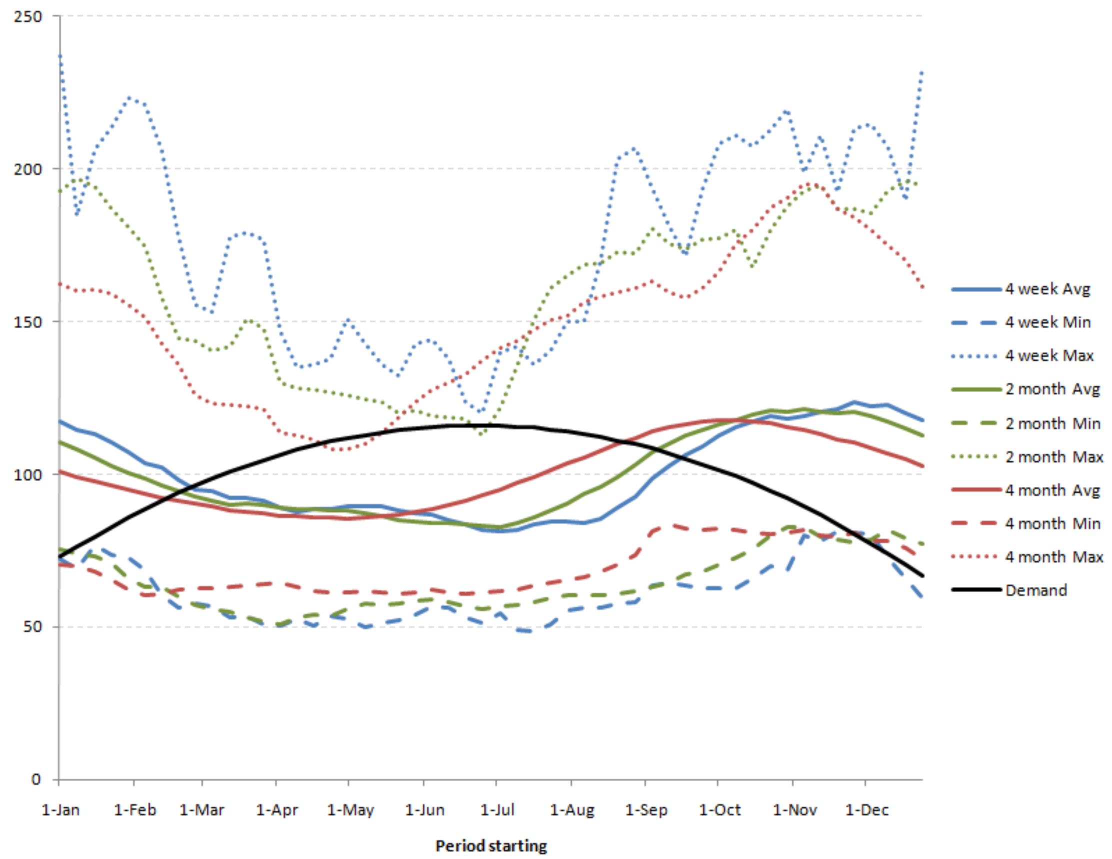
Wholesale electricity spot prices vary across each day and over seasons reflecting supply and demand conditions. Generally, prices are higher in high demand periods, because of the need to call upon higher priced thermal generation to meet such demand.

Where a hydro generator has sufficient flexibility, it will seek to release its water in a pattern to maximise the volume of generation during higher value periods. This also benefits New Zealand by increasing supply at times of greatest need. Reducing the useful operating range in a storage reservoir will reduce the ability of the generator to defer water use from low value periods to higher value periods in the future.

To illustrate this the following chart overlays a simple within-year demand profile onto the average inflow chart from the above example.

59 Having a higher minimum flow may also have the counter-intuitive impact of reducing *achievable* flows during a sustained dry period. This arises because during the early stages of a sustained dry period, a higher minimum flow requirement could result in greater releases of water than would otherwise occur. This may draw down the reservoir to such an extent that if the dry period continues there is not enough water left in the reservoir to meet regulated minimum flow requirement.

60 To give an extreme analogy, it would be like saying that a driver must never let the petrol tank go below half before they are required to fill up. This would halve the useful range of the car.



Thus, the hydro generator will aim to manage its storage to target the higher periods of demand, whilst meeting the constraints of its minimum flow requirements.

The following charts show the consequential optimal storage patterns for this example hydro generator in two different situations:

- No minimum flow requirements; and
- A minimum flow requirement equivalent to 80% of mean.

Figure 27: Storage trajectories for scenario with no minimum flow requirement

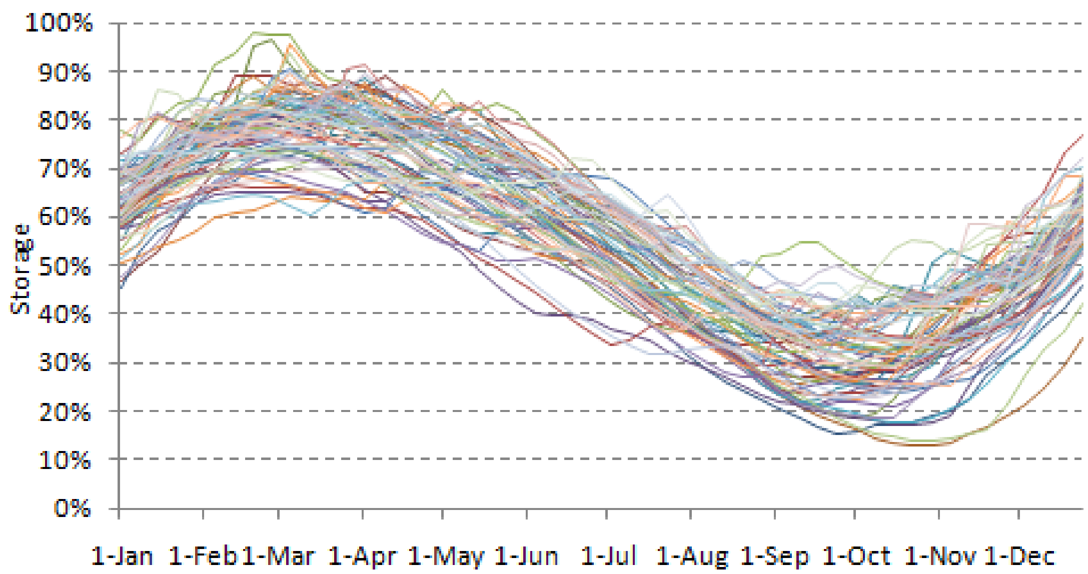
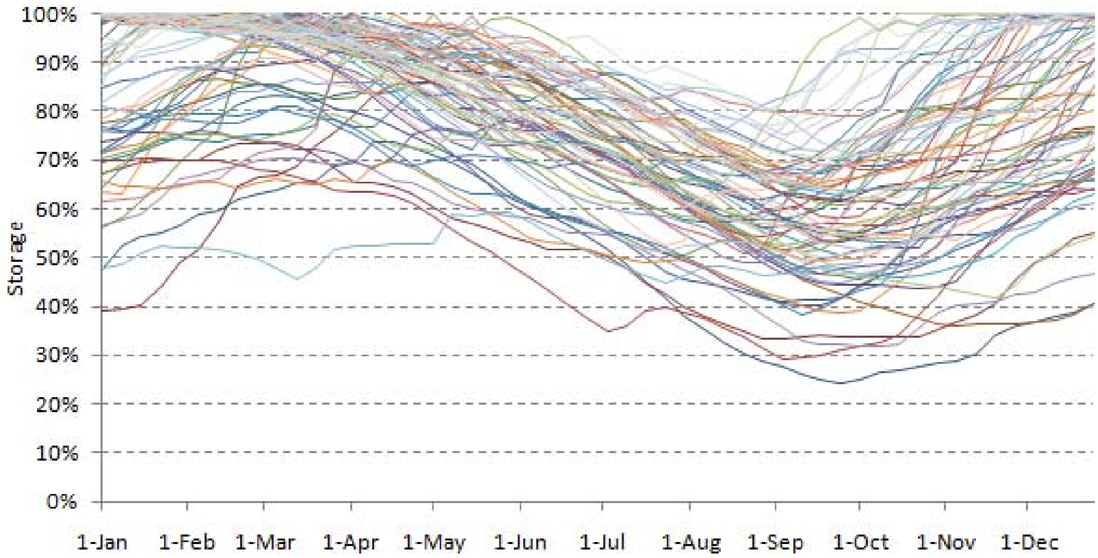


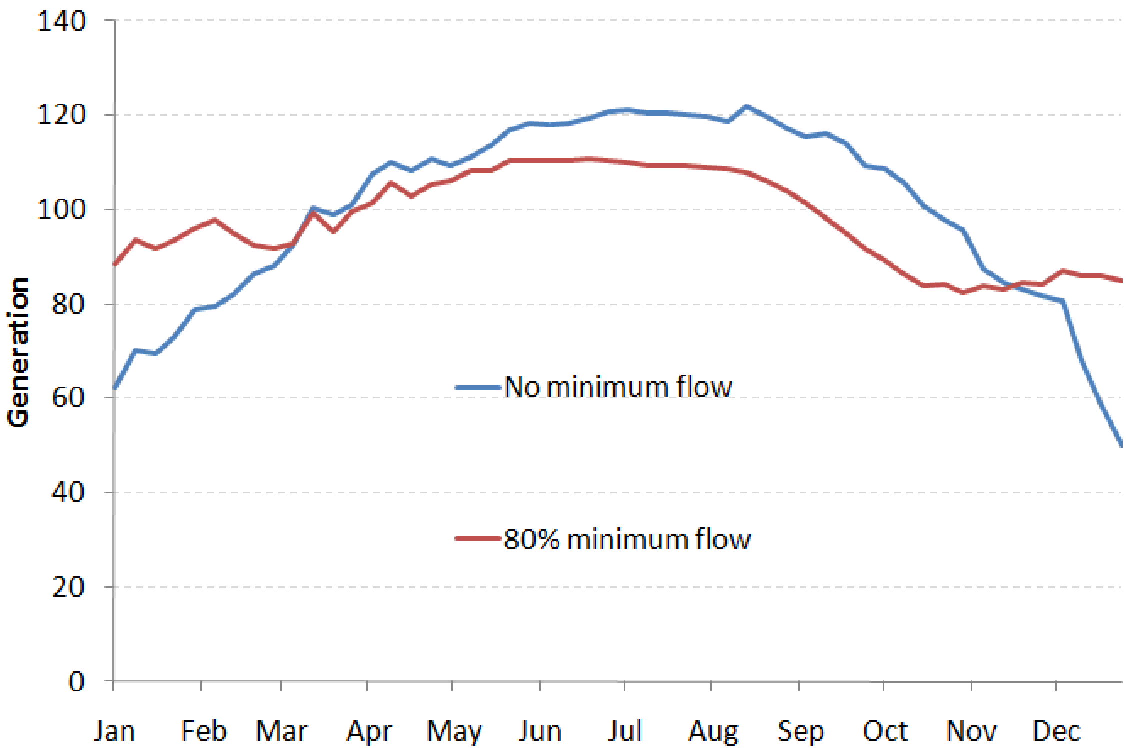
Figure 28: Storage trajectories for scenario with an 80% of mean minimum flow requirement



As can be seen, the storage trajectories in the second scenario are generally higher, but also more spread out. This is indicative of a reduced ability to target storage and generation at higher value periods.

The impact in terms of the average within-year generation for the two scenarios is shown in Figure 29 below

Figure 29: Illustrative impact on within-year hydro generation profile arising from increased minimum flows

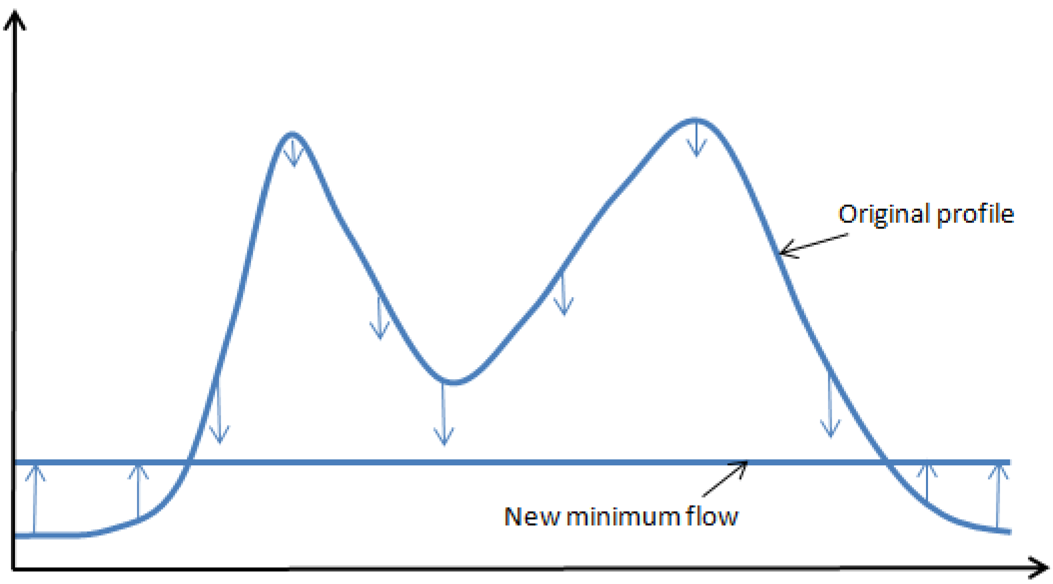


As can be seen, as the minimum flow increases, less water is used in the higher value winter months and more is used in the lower value summer months. From an overall New Zealand perspective the higher minimum flow requirement results in extra costs due to:

- An increase in the requirement to use higher priced thermal generation in the winter months that costs more than the benefit from any reduced requirement to use relatively lower priced thermal generation in the summer months; and
- An absolute increase in thermal generation due to increased hydro spill (2.1% of potential hydro generation in this example). This spill occurs from situations where the minimum flow requirement results in the hydro generator holding storage levels at such a high level that if a high inflow sequence eventuates, the water cannot be usefully used. This is illustrated by many of the storage trajectories in Figure 28 reaching the 100% level.

Whilst the above example indicates a within-year impact, of more inefficient use of water, the same effect will occur for within-day sculpting of hydro generation as illustrated in the following diagram.

Figure 30: Illustration of reduced within-day flexibility from increased minimum flow requirements



Clearly, the scale of this loss of flexibility effect will impact different generators differently according to the physical nature of the scheme, and their current consent levels.

Appendix C. Consideration of potential issues associated with valuation approaches

This appendix considers the extent to which the inherent uncertainties associated with the type of modelling exercise could result in material errors in estimation of the cost impacts of altered minimum flow regimes.

Potential 'counter-balancing' actions by other hydro generators

The altered generation profiles calculated by the generators have been developed in isolation.

A key challenge in this modelling exercise is to take into account the ability of other hydro schemes to react to changed generation profiles from existing schemes. For example, if one hydro generator were to shift its generation profile from higher demand periods to lower demand periods it is possible there could be a counter response from other generators shifting their water from low demand periods to high demand periods. In theory, if such an outcome were to occur exactly there would be no net system cost in terms of increased fuel burn or increased capital investment. Accordingly, the system cost impact estimated using the methodology set out in section 3 would be a gross over-estimate.

In practice, although such 'counter-balancing' is likely to occur to some extent, it is likely that there will be constraints on the ability of other hydro generators to respond in such a fashion. In particular, there are likely to be constraints on the ability of other hydro generators to shift their generation at two of the key times which will have a bearing on the system cost consequences of such altered generation, namely:

- times of generation scarcity; and
- low-demand times of generation surplus.

The times of most acute generation scarcity occur during a relatively small period of time of peak winter demand during dry periods. At such times prices are at extreme levels (reflecting such capacity scarcity) and it is understood existing hydro generation is already operating to its maximum capability. Accordingly, if altered minimum flows for a particular hydro generator were to result in it reducing its output at such times, it is reasonable to assume that an existing hydro generator would be unable to counter-balance such loss by increasing its output at such times *more than it is already doing*. Accordingly, it is reasonable to assume that loss of hydro generation at system peak will give rise to an increase in the requirement for non-hydro capacity at peak.

The times of greatest generation surplus are at low demand periods – i.e. night times during the summer and shoulder months, and particularly during relatively wet periods. If water from a hydro-scheme is shifted away from day periods into night periods, it is considered that most hydro schemes will have limited flexibility to counter-balance such changes by shifting their water away from such low demand periods *more than they already have done*.

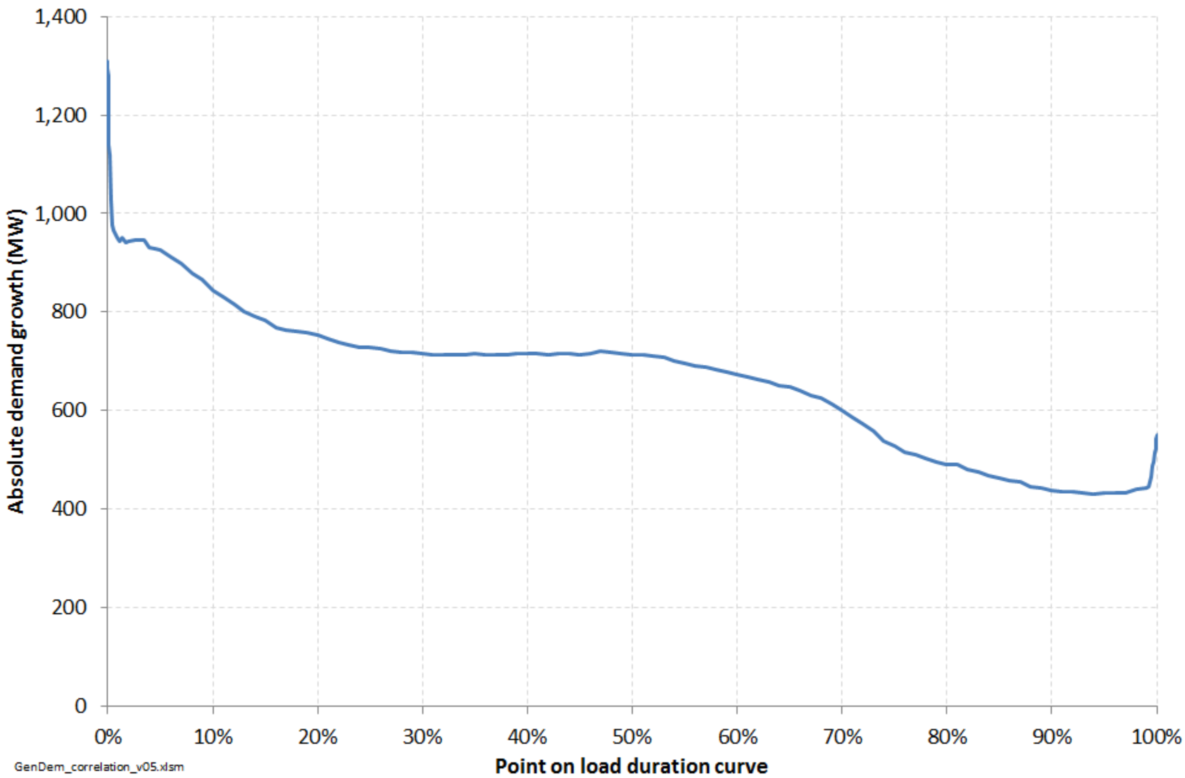
A number of factors suggest why this may be the case:

- Firstly, as is illustrated in Figure 12 on page 25, there exists a very strong price signal for generators with flexibility to shift their generation away from night periods to day periods and from summer to winter. If all generators had total flexibility, such arbitrage behaviour would result in prices being evened out to give a flat within-day and within-year price shape. This happens to a significant extent in Norway which has much greater amounts of hydro storage flexibility than New Zealand, and results in a much flatter within-day and within-year shape of prices. The fact that this doesn't happen in New Zealand suggests that there are constraints on the ability of hydro generators to shift their water away from periods of surplus to periods of relative scarcity more than they are doing so already.

- Secondly, as illustrated in Figure 31 below, growth in demand over the last twelve years has been peaky. i.e. peak demand has grown by approximately 1,000 MW, whereas night demand has only grown by approximately 450 MW. This represented an opportunity for hydro generators to progressively sculpt their water into the peaks, with the resulting loss of hydro generation in low-demand periods made-up by increased non-hydro baseload generation as schematically represented by Figure 32 below. However, as illustrated in Figure 33 below, this appears not to have happened, with the seasonal and diurnal pattern of hydro generation remaining largely the same – with the main difference in generation in a year being driven by different hydrological states (i.e. whether it is wet or dry). Again, this suggests constraints on the ability of hydro generators to shift their water away from low demand periods more than they are already doing.

As such, it appears likely that a shift of hydro generation into low demand periods will not be materially counter-balanced by other hydro generation shifting away from such periods, but will instead result in non-hydro baseload generation being displaced.

Figure 31: Differential growth in the national demand load duration curve from 1998 to 2011



Source: Concept analysis using Electricity Authority centralised data set data

Figure 32: Illustration of hypothetical combination of geothermal build plus increased sculpting of hydro to meet peaky demand growth[61]

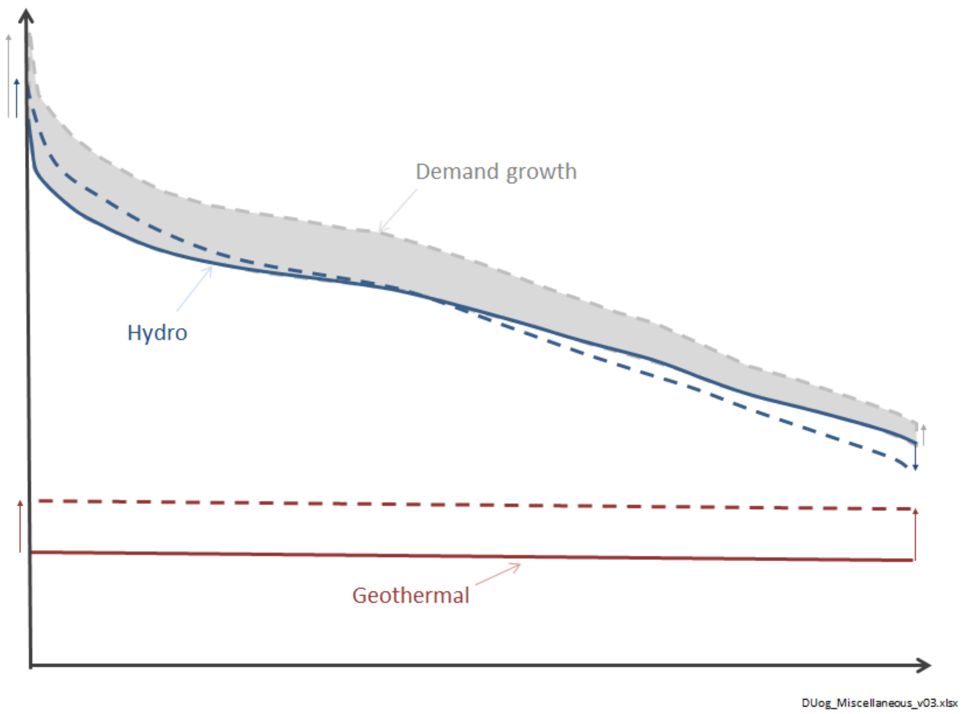
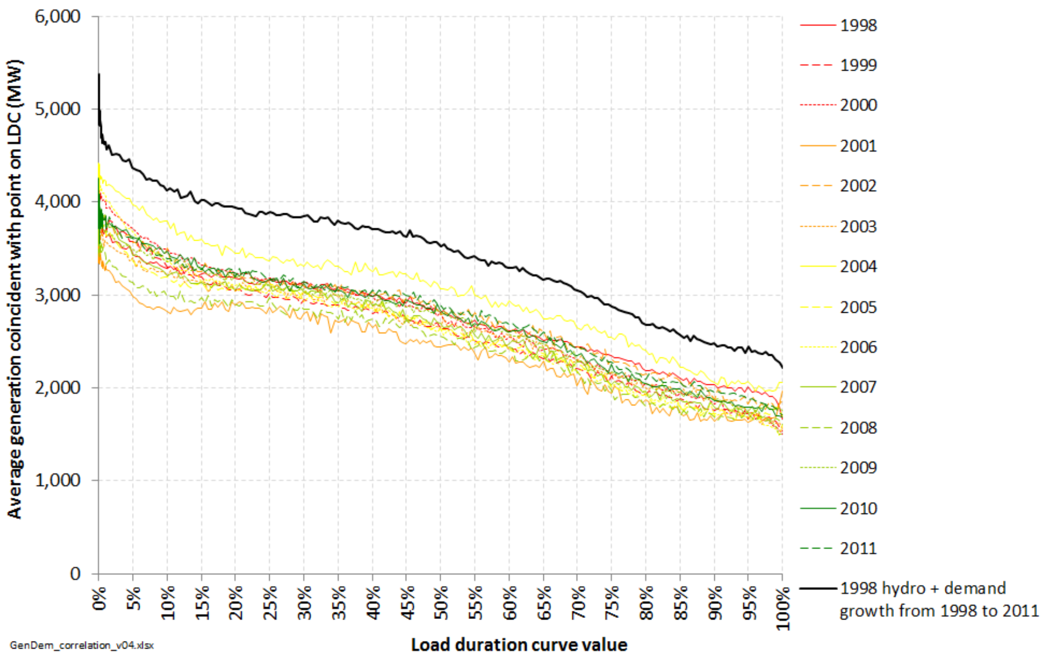


Figure 33: Average hydro generation coincident with point on the national load duration curve



Source: Concept analysis using Electricity Authority centralised data set data

61 The solid blue and red lines represent the hydro and geothermal generation profiles at the start of the period, and the dashed lines represent their respective generation profiles at the end of the period (e.g. after ten years) in order to meet the peaky demand growth represented by the grey shaded area.

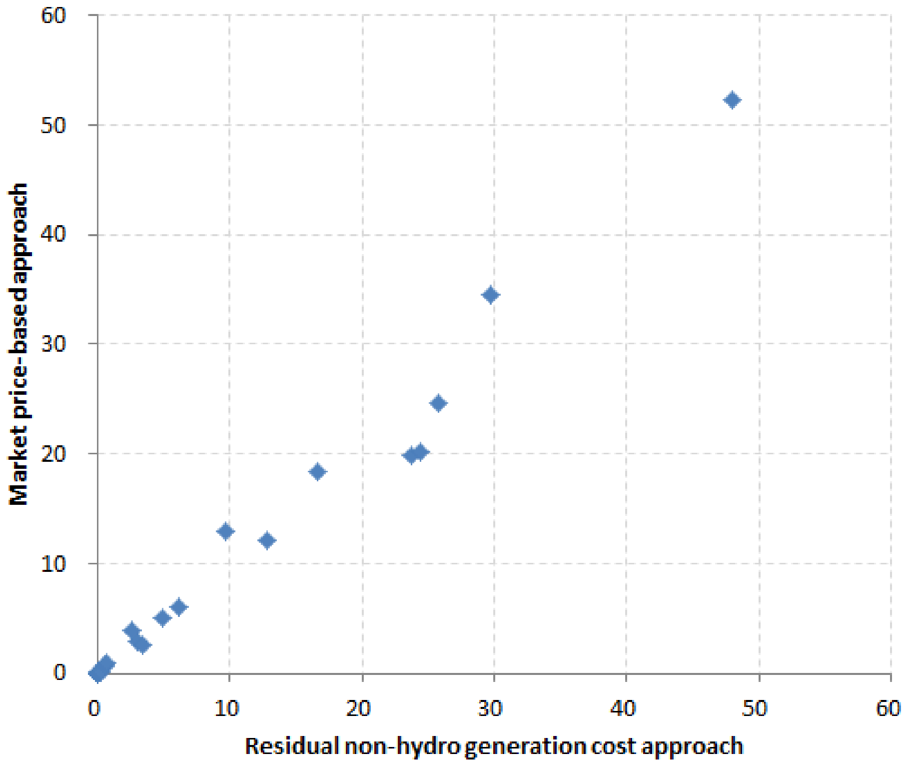
It shows hydro generation being used less during low demand periods, with water stored for use at such times to enable increased generation at high demand periods in order to meet the peaky nature of the demand growth. This reduced hydro generation at low demand periods is met by increased geothermal generation, the scale of which is greater than the scale of demand growth at such low demand periods.

Comparison of the market price and residual non-hydro generation cost-based approach

The two different modelling techniques described in section 3 approach the problem of estimating the likely cost implications of altered hydro generation outcomes from very different angles.

As can be seen in Figure 34 below, there is a reasonably close alignment between the two approaches, which lends confidence that the cost estimates are unlikely to be materially wrong.

Figure 34: Comparison between market price-based and residual non-hydro generation cost-based approaches for estimating the economic cost of altered minimum flows for different schemes and minimum flow scenarios



Treatment of un-served energy

Another point to consider is the potential impacts of altered hydro generation outcomes on un-served energy – i.e. the amount of load not served due to having insufficient generation.

In this respect it is considered that changes to the operations of hydro schemes would <u>not</u> systematically alter the amount of un-served energy on the system. This is because the economics of addressing un-served energy are such that it is fundamentally a trade-off between either:

- building *thermal generation* to meet infrequent periods of peak demand and/or hydro shortfall; **or**
- calling upon varying types and quantities of demand-side response, ranging from various types of voluntary load curtailment at times of shortage[62], through to involuntary load shedding.

It is not considered that changing hydro dispatch patterns will fundamentally alter this trade-off between thermal economics and demand-side curtailment.

62 Such curtailment can take the form of regularly shifting consumption away from high demand periods, through to voluntarily scaling back consumption during infrequent periods of shortage. The price threshold beyond which it would be economic for consumers to scale back varies significantly among the different types of consumer.

The one caveat to this, is that there may be impacts on un-served energy if the adjusted hydro operations happen very quickly and the system has not had time to adjust to a new equilibrium through building (or even retiring) new plant, as described further on page 38 above.

Other considerations

This evaluation has been undertaken against the background of the current electricity market. If/when regional councils consider altering minimum flows there could be a range of changes to the market which may alter the economic and consumer price outcomes described in this report.

Existing consents have been assumed able to be altered for the purposes of this evaluation. In reality there may be constraints on the ability to alter such consents.

Appendix D. Description of electricity generation schemes

This section provides a description of each of the schemes studied, and details the results of the modelling undertaken to estimate altered generation patterns.

The schemes that have been selected for examination in this study are:

- Eight hydro schemes:
  - Waitaki
  - Manapouri
  - Clutha
  - TPS
  - Waikato
  - Waipori
  - Wheao
  - Branch
- The Huntly thermal power station thermal scheme

The hydro schemes selected account for approximately 93% of New Zealand's hydro generation. Further, they span the spectrum of different hydro scheme characteristics in terms of: scale (large to small); consumptive versus non-consumptive sources of water; relative storage capability (seasonal versus intermediate); 'chains' of generation versus single generator schemes; and timing of inflows.

The Huntly power station was the only thermal scheme selected as it is understood to be the only thermal scheme going forward that has the potential to be affected by river heating constraints. In this respect, Contact have advised that with the commissioning of the Te Mihi geothermal power station a significant proportion of the geothermal fluid from the Wairakei scheme will now be re-injected back into the ground. This will have the effect of lowering the Waikato river flow threshold below which river heating constraints could have an impact on Wairakei generation to materially below historical and projected minimum flows on the Waikato river[63].

As set out in section 2.3.1 above, the framework used to classify the different hydro schemes distinguishes between

- consumptive and non-consumptive flows (where the phrase 'consumptive' is used to indicate flows from diversions); and
- storage which is sufficiently large to allow the storage of some inflows for up to a few months ('seasonal' storage), or merely for an hour or two up to a few days ('intermediate' storage).

The flow data in the various tables (i.e. natural low-flow levels and consented levels) has generally been provided by the generators responsible for each scheme.

[63] To test this assertion, Concept compared the revised flow threshold value provided by Contact (measured at just below the Taupo gates), with the historical and projected flows provided by Mighty River Power. In all cases, the flows were materially above this flow threshold.

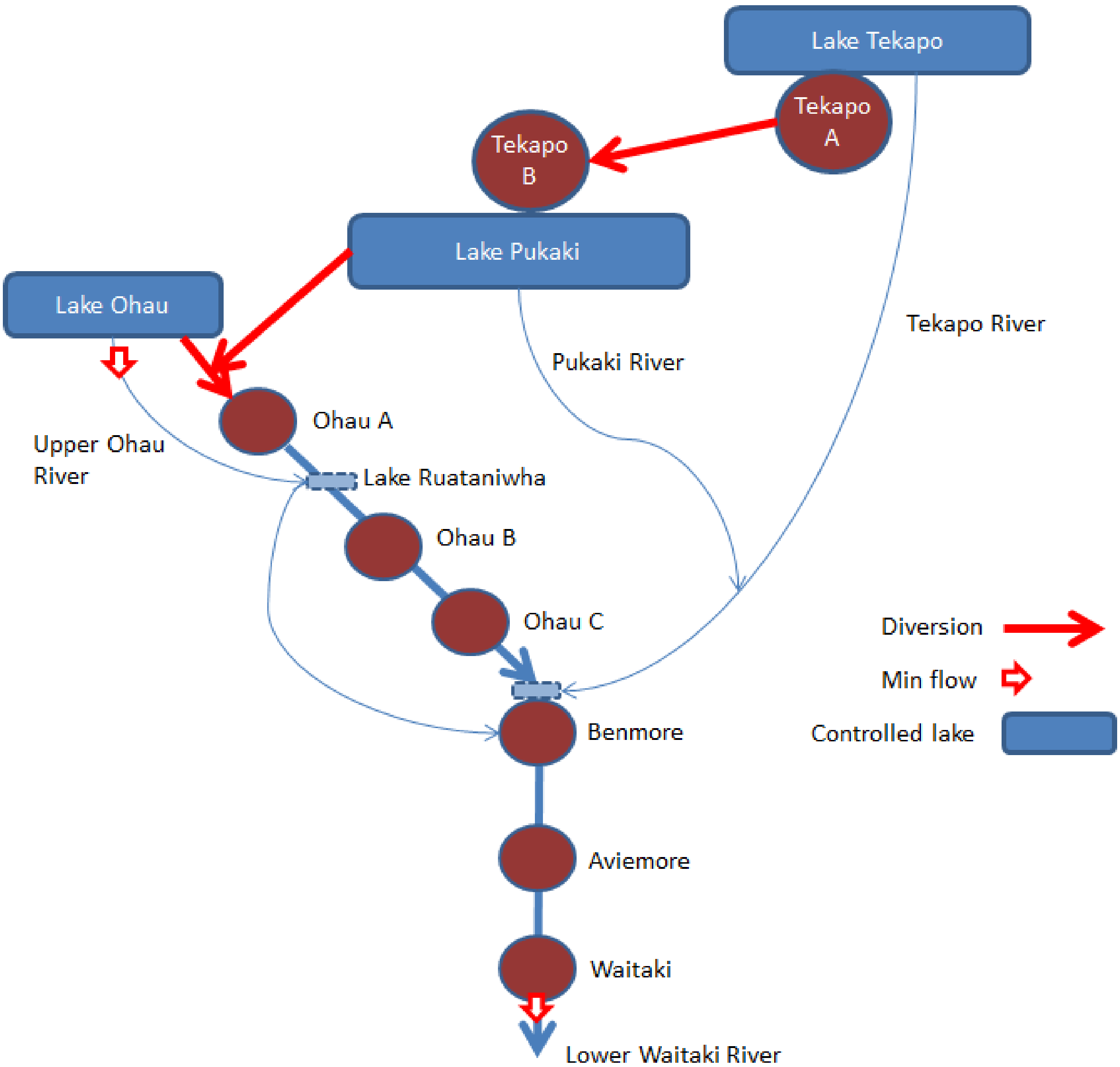
Waitaki Hydro Scheme (Meridian and Genesis Energy)

Overview

The Waitaki hydro scheme includes Lakes Tekapo, Pukaki (controlled seasonal storage lakes) and Lake Ohau (largely uncontrolled) and 8 power stations with intermediate storage lakes Ruataniwha, Benmore, Aviemore and Waitaki.

Water is diverted along purpose-built canals from the Ohau, Tekapo and Pukaki Rivers. These original rivers are used for flood/spill routing purposes.

Figure 35: Schematic of Waitaki hydro scheme



The Tekapo A & B stations are owned by Genesis Energy, with the remainder of the Waitaki scheme owned by Meridian.

The following tables set out the statistics relating to the electricity generation and hydro storage capabilities of the scheme.

Table 2: Waitaki hydro scheme generation data

Stations	MW Capacity[64]	Avg GWh pa		
		Consumptive flows	Natural flows	Total
Tekapo A	25	136	0	136
Tekapo B	160	840	0	840
Subtotal (Genesis Energy)	**185**	**976**	**0**	**976**
Ohau A	264	1,113	0	1,113
Ohau B	212	934	0	934
Ohau C	212	928	0	928
Benmore	540		2,219	2,219
Aviemore	220		923	923
Waitaki	105		490	490
Subtotal (Meridian)	**1,553**			**6,607**
Scheme	**1,738**			**7,583**

Table 3: Waitaki hydro scheme storage data

Storage	Seasonal GWh	Intermediate GWh	% GWh (scheme) flows via storage
Lake Tekapo	~800		40%
Lake Pukaki	~1,700		40%
Lake Ruataniwha		~2	??
Lake Benmore		~27	??
Lake Aviemore		2.3	??
Lake Waitaki		0.6	??

64 It should be noted that in most cases, the generation station at a particular dam is made up of multiple generating units. For example the 105 MW Waitaki station is comprised of 7 x 15 MW units.

Table 4 below details the principal minimum flow consents that apply to the Waitaki scheme. This table also shows the seven day mean annual low flow (7DMALF) which is a measure of the natural lowest flows along the rivers at those particular points. The unit of measure is the cumec, being a cubic metre of water per second.

Table 4: Waitaki hydro scheme flow data (cumecs)

	7DMALF	Consented minimum flows
Upper Tekapo River	30	0
Pukaki River	37	0
Upper Ohau River	8	12 summer, 8 winter
Waitaki dam	120[65]	120

As can be seen, the current consents allow for The Upper Tekapo and Pukaki rivers to have zero flows at times, whereas the consent requires that flows along the lower Waitaki do not fall below the natural minimum flow – although effectively the scheme is operated such that minimum flows at Waitaki never fall below 150 cumecs (i.e. above the natural minimum) because the minimum flow is an instantaneous limit, and the scheme needs to be operated such that if one of the 15 MW units tripped off flows do not fall below 120 cumecs[66].

Indicative flexibility

The Waitaki scheme has around 60% of NZ's hydro storage capacity providing the primary source of seasonal hydro-electricity supply flexibility. Minimum flows downstream of Waitaki power station constrain the management of the storage lakes and the operation of Waitaki power station. The outflow of Lake Ohau is largely uncontrolled. The scheme overall has a reasonable degree of seasonal and short term flexibility as illustrated below which shows average half hourly generation averaged by season over a 5 year period[67].

65 Meridian have advised that the natural 7DMALF figure may be lower than this. However, at the time of the report's publication, they had yet to complete the analysis to establish this value (noting the non-trivial nature of such hydrological analysis).

66 i.e. The flow through a unit is approximately 30 cumecs.

67 Average generation for each half hour in the 5 years ending 30 September 2012.

Figure 36: Waitaki generation scheme statistics by season

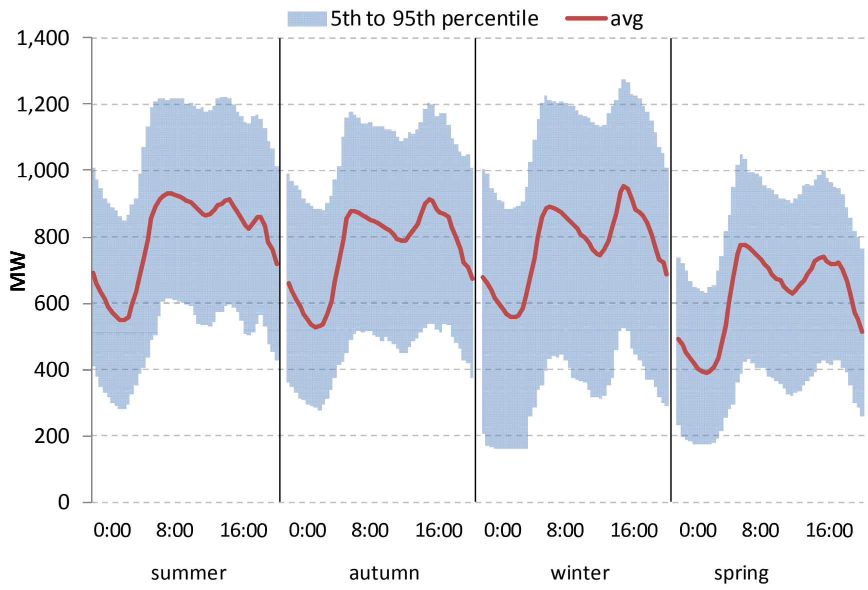
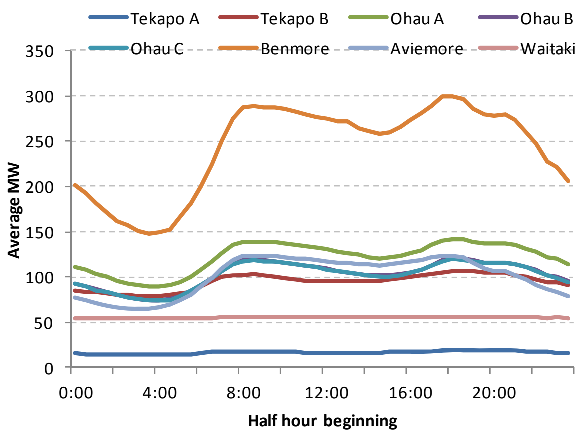
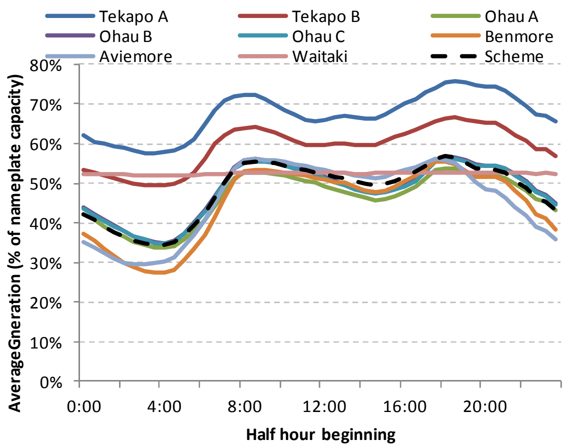


Figure 37: Average generation from Waitaki hydro scheme stations





High level implications of altering minimum flows

As can be seen from examination of Figure 35 above, increasing minimum flows at points that are 'high-up' in the scheme would result in less water being available for electricity generation at stations lower down in the chain. Thus increasing minimum flows in

- the Ohau river would reduce energy supply from some of the Ohau stations.
- the Pukaki river would reduce energy supply to all of the Ohau stations
- the Tekapo river would reduce energy supply to all of the Ohau stations and to Tekapo A & B, plus would also reduce inflows into Lake Pukaki storage.

As well as reducing the absolute amount of generation from the scheme, collectively all such changes would also tend to reduce the flexibility of the scheme, making it more 'run of river', at least seasonally.

Even though the minimum flows from the Waitaki are already at natural levels, it would be possible to increase the minimum flows beyond these natural levels through use of the significant seasonal storage capabilities from Lakes Pukaki and Tekapo. However, increasing the minimum flow from the Waitaki power station would further constrain the operation of the scheme, with more 'must-run' generation required, limiting flexibility on both a seasonal and diurnal basis.

The nature and scale of impact of an increase in minimum flows wouldn't just depend on where in the scheme such an increase was required, but also the *combinations* of any increases at multiple different points. Thus, it is possible that the impact of changes in minimum flows at two different points may not be simply equal to the sum of the two minimum flow changes.

It should also be appreciated that where consented minimum flows are below the natural minimums these are not unmitigated. Thus Meridian, as a condition of its consents, undertakes a series of programmes aimed at improving the local environment. If the consented minimum flows were increased towards (or indeed above) natural minimum flow levels, it is therefore possible that Meridian would no longer be required to undertake these environmental programmes to the same extent.

Thus, any potential improvement in environmental outcomes from an increase in minimum flows may be offset by a worsening in environmental outcomes from the reduction in these environmental mitigation programmes.

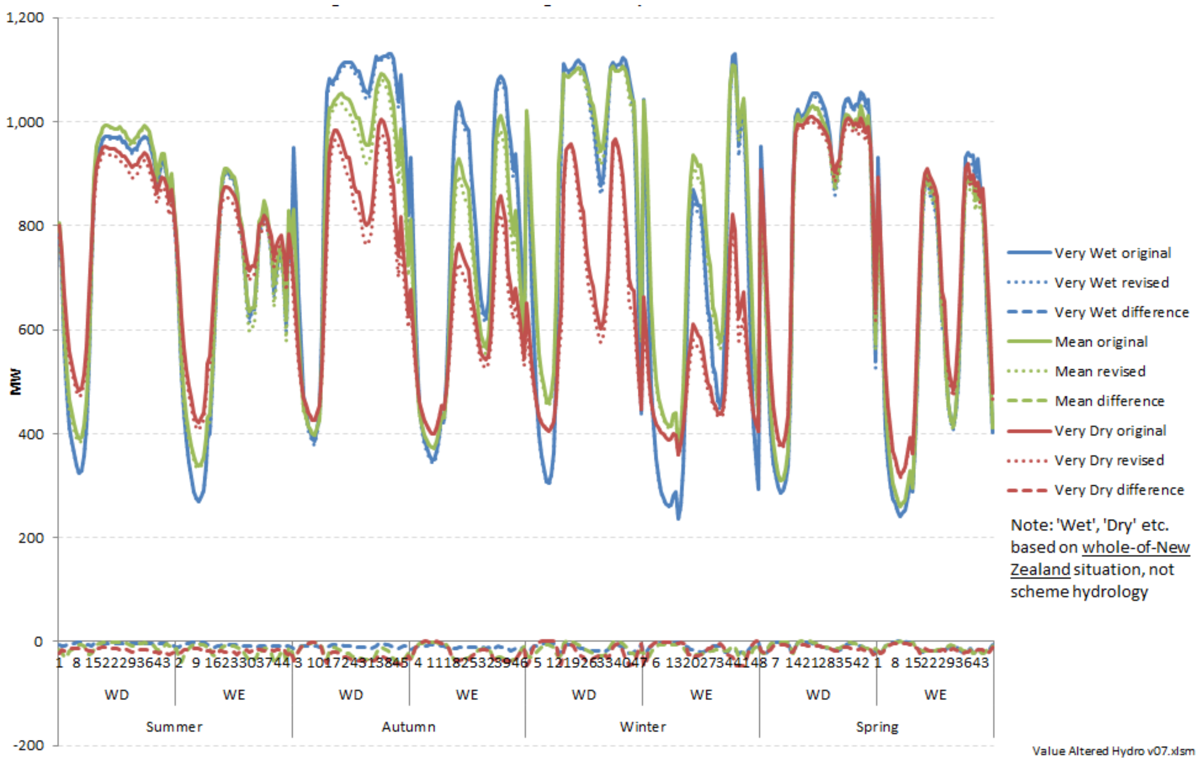
Results of Meridian modelling

Meridian undertook modelling for two different scenarios – a 10% and a 40% increase in minimum flows against current consent levels for all four consented points on the scheme as set out in Table 4 above. Because the Tekapo and Pukaki river consents allow zero flows, the 10% and 40% increase scenarios assumed that minimum flows were set to 10% and 40% of natural MALF, respectively.

The modelling considered the outcomes for 27 historical inflow years (1980 to 2006). As set out in section 3.2 above, each season for each historical inflow year was assigned one of five quintile states (ranging from 'Very Dry' through to 'Very Wet') representing the overall New Zealand hydrological state, rather than the scheme-specific hydrological state.

The following figure shows the average within-day and within-season impact of altered minimum flows for the stations owned by Meridian on the Waitaki scheme (i.e. excluding Tekapo A & B which are owned by Genesis Energy) for the 10% increase scenario.

Figure 38 Altered average Waitaki_Meri generation profiles for the 10% increase scenario[68]



The 'difference' lines at the bottom of the graph show that the increase in minimum flows will lead to a loss of generation, and that this loss will be different at different times.

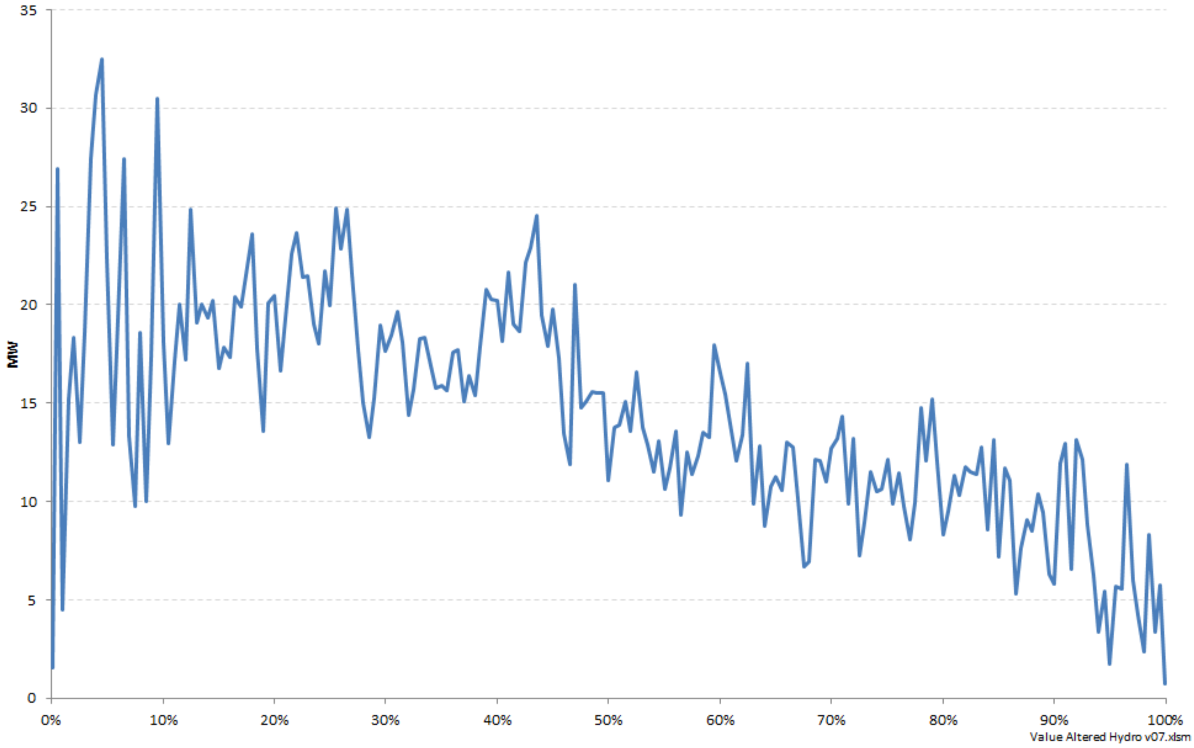
An alternative way to consider this change is to consider the likely change on the residual demand for non-hydro generation. Section 3.2 and Appendix A above describe how to consider the concept of residual demand and residual demand duration curves.

The following figure shows the likely change in the residual demand duration curve for non-hydro generation. It appears that the loss of Waitaki generation from the 10% scenario will be met by a combination of:

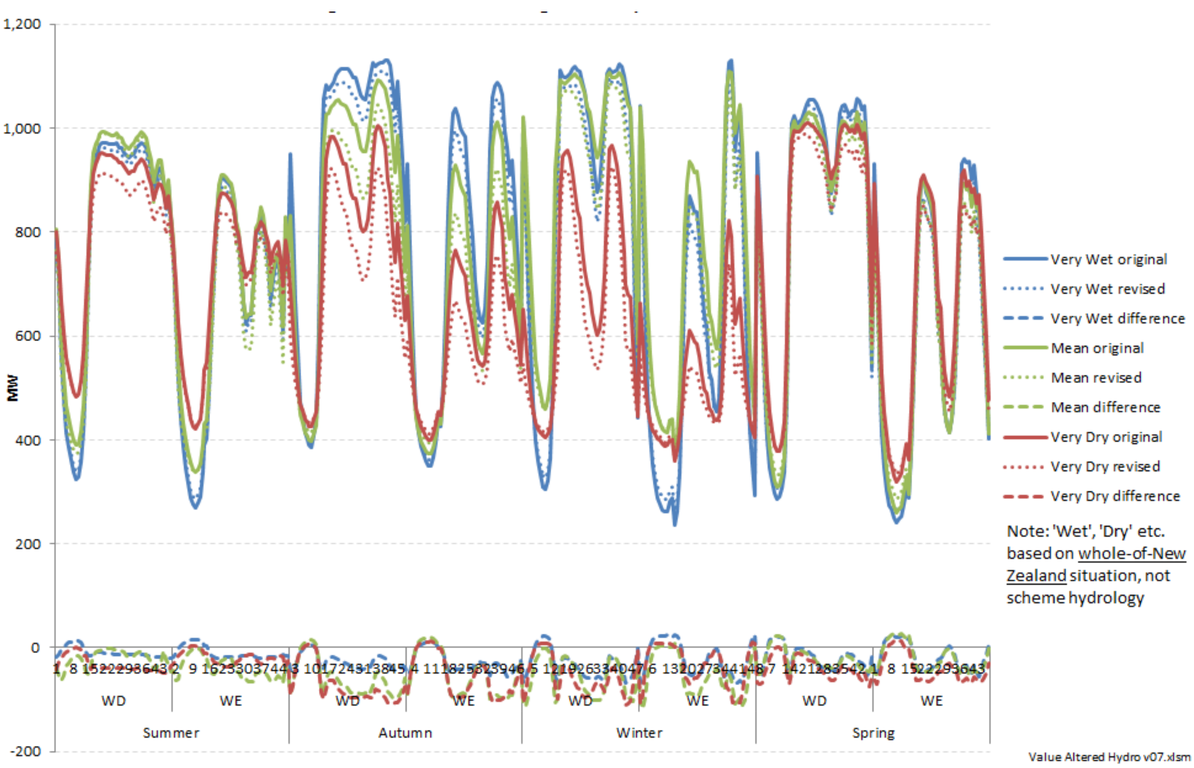
- an increase in non-hydro baseload generation (as indicated by the curve at approximately the 85% level being above zero)
- increased mid-merit thermal plant operation (Huntly & CCGTs) (as indicated by the curve for lower capacity factors (i.e. less than 85%) being higher than the 85% level)
- some increase in new peaking capacity (as indicated by an increase in the peak (i.e. very leftmost part of the residual non-hydro duration) curve at a level which is greater than the likely increase in new baseload generation)

68 The x-axis is split into four seasons, with a weekday (WD) and weekend (WE) for each season, and 48 half-hours within each day.

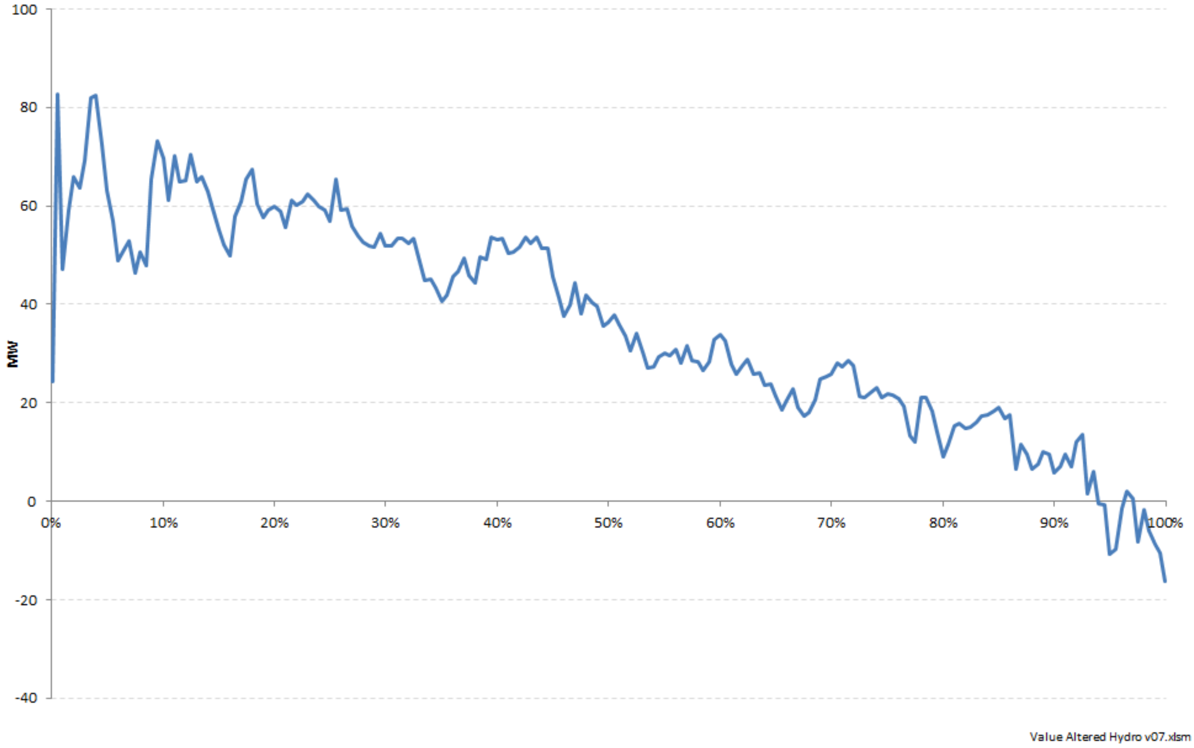
Figure 39: Change in the residual demand curve for non-hydro generation arising from the Waitaki_Meri '10% increase' scenario



The figures below show the same type of analysis as for above, but for the 40% increase scenario.



As well as there being a greater absolute loss of hydro generation compared to the 10% increase scenario, the following figure indicates that this will predominantly be met by an increase in mid-merit thermal and peaking generation, and proportionately much less increased baseload non-hydro generation compared to the 10% scenario. This will result in the $/MWh cost of such lost generation for the 40% scenario being materially higher than for the 10% scenario.



Results of Genesis Energy modelling

Genesis Energy undertook analysis of the impact of altering minimum flows along the Tekapo river for three scenarios:

- 10% increase on existing minimum flows.
- 40% increase on existing minimum flows
- Setting minimum flow requirements at 80% of 7DMALF

For those diversion points where existing flows are allowed to be zero under current consents, the minimum flow for the first two scenarios was set at 10% or 40%, respectively, of 7DMALF)

The results of the analysis provided to Concept was in the form of a series of monthly GWh values for 79 historical inflow years (namely July 1931 to June 2010). Each month was assigned to one of the five hydrological quintiles (i.e. Very Dry through to Very Wet) based on whole-of-New Zealand hydrology, rather than TPS-specific hydrology.

No modelling was undertaken by Genesis Energy regarding altered within-month / within-day generating patterns. Accordingly, Concept converted the monthly values provided by Genesis Energy into within-month profiles using historical observed generating profiles from the period 1998 to 2011. This process used observed historical profiles consistent with the monthly GWh values produced by Genesis Energy. For example, if a projected level of generation for July for one of the historical inflow years was X GWh, the within-month profile used by Concept was based on the historical July month whose monthly generation was closest to X GWh. This was intended to produce within-month generation profiles which were broadly consistent with the projected GWh for a particular month. However, it should be recognised that this is a relatively simplistic process and will introduce greater degrees of uncertainty into the analysis. No analysis has been undertaken to determine whether this may systematically over- or under-estimate the impact.

In terms of the average loss of generation for Waitaki_Tekapo, the results of the analysis are set out in the table below

Scenario	Average loss of generation	
	GWh	Percentage
10% increase	34	3.4%
40% increase	142	14.6%
80% of 7DMALF	287	29.4%

With regards to the loss of flexibility, it would appear that there is not any systematically greater loss of generation during dry periods than wet periods.

However, it is hard to draw conclusions with regards to the loss of within-month / within-day flexibility as it is based on a simple factoring approach using historical profiles rather than a proper optimisation. Doing a number of cross-checks it would appear that the valuation approach may be under-estimating the loss of within-day flexibility. However, the level of under-estimation is not considered to be of a scale that would give rise to the estimated costs being radically different to those shown in the results.

Waitaki modelling update

When comparing the Meridian and Genesis analysis of the Waitaki scheme, it became clear that inconsisent assumptions were being used with regards to natural flows on the Tekapo river. Subsequent hydrological analysis by Meridian revealed that the natural flow levels assumed for both the Tekapo and Pukaki rivers were incorrect. (The Tekapo MALF was too low, whereas the Pukaki was too high).

Subsequently Meridian undertook updated analysis to estimate the scale of impact of using these revised figures. Their initial analysis suggests that the Waitaki_Meri numbers set out above (which are based on the original Meridian analysis) probably under-estimate the scale of impact by approximately 10%. However, given the '11th hour' nature of this updated information, it has not been possible to incorporate it within Concept's modelling.

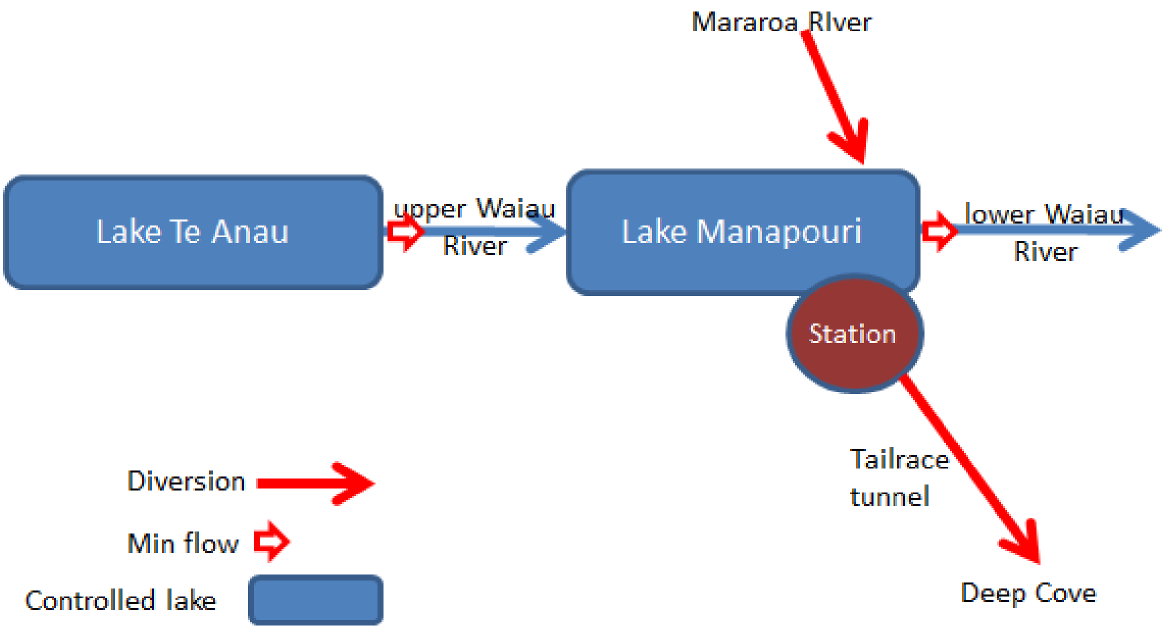
Manapouri Power Scheme

Overview

The Manapouri hydro station diverts water from Lake Manapouri through the power station and tailrace tunnels to Deep Cove. Subject to water quality (turbidity), water is also diverted into Lake Manapouri from the Mararoa River. Lakes Te Anau and Manapouri provide storage.

The following schematic illustrates the scheme, including showing where water is diverted away from original water-ways into the scheme, and which points in the scheme are currently subject to minimum flow requirements.

Figure 40: Schematic of Manapouri hydro scheme



As is shown in the table below, all of Manpouri's generation is from consumptive flows.

Table 5: Manapouri generation data

Station	MW Capacity	Avg GWh pa		
		Consumptive flows	Natural flows	Total
Manapouri	800	~5,100		~5,100

Table 6: Manapouri storage data

Storage	Seasonal GWh	Intermediate GWh	% GWh (scheme) flows via storage
Te Anau	280		65%
Manapouri	160		100%

Table 7: Manapouri flow data (cumecs)

Flow data	7DMALF	Consented minimum flows
Upper Waiau	129	80 – 115
Lower Waiau	209	16 summer, 12 winter

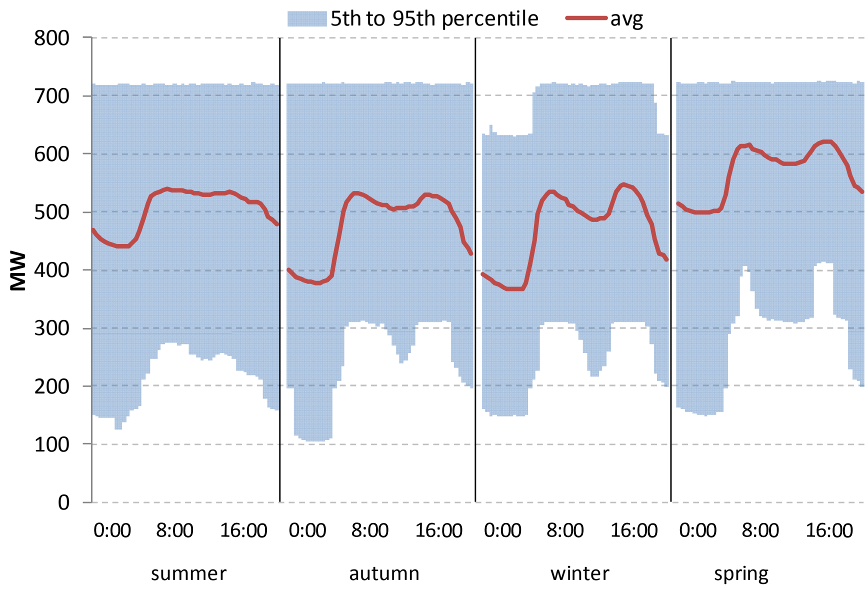
Indicative flexibility

The management of Manapouri storage and generation is constrained by complex lake operating rules (which aim to mimic natural lake level patterns over time), relatively small lake operating ranges compared to inflows, which can be very volatile, and minimum flow requirements in the

Waiau River. Water from the Mararoa River is also diverted into Lake Manapouri provided water quality (turbidity) meets requirements. .

The red lines in the chart below show half hourly Manapouri generation averaged by season over a 5 year period[69]. The shaded bands represent the 5th to 95th percentile generation range for each season. The chart illustrates that while on average the scheme responds to market demands to some extent, it also has a significant run of river element given the level (and variability) of inflows relative to storage capacity.

Figure 41: Manapouri generation statistics by season



High level implications of altering minimum flows

Increasing lower Waiau minimum flows or reducing Mararoa diversions would reduce energy supply from the scheme.

Increasing lower and upper Waiau minimum flows would further complicate storage management and affect seasonal supply flexibility.

Results of Meridian modelling

The modelling considered the outcomes for 27 historical inflow years (1980 to 2006). As set out in section 3.2 above, each season for each historical inflow year was assigned one of five quintile states (ranging from 'Very Dry' through to 'Very Wet') representing the overall New Zealand hydrological state, rather than the scheme-specific hydrological state.

The following figures show the results of Meridian's modelling associated with increasing current consented minimum flows for the lower Waiau by 40%. As can be seen, because the current consented flows are low compared with natural minimum flows, a 40% increase in such consented flows has a relatively small % impact on generation.

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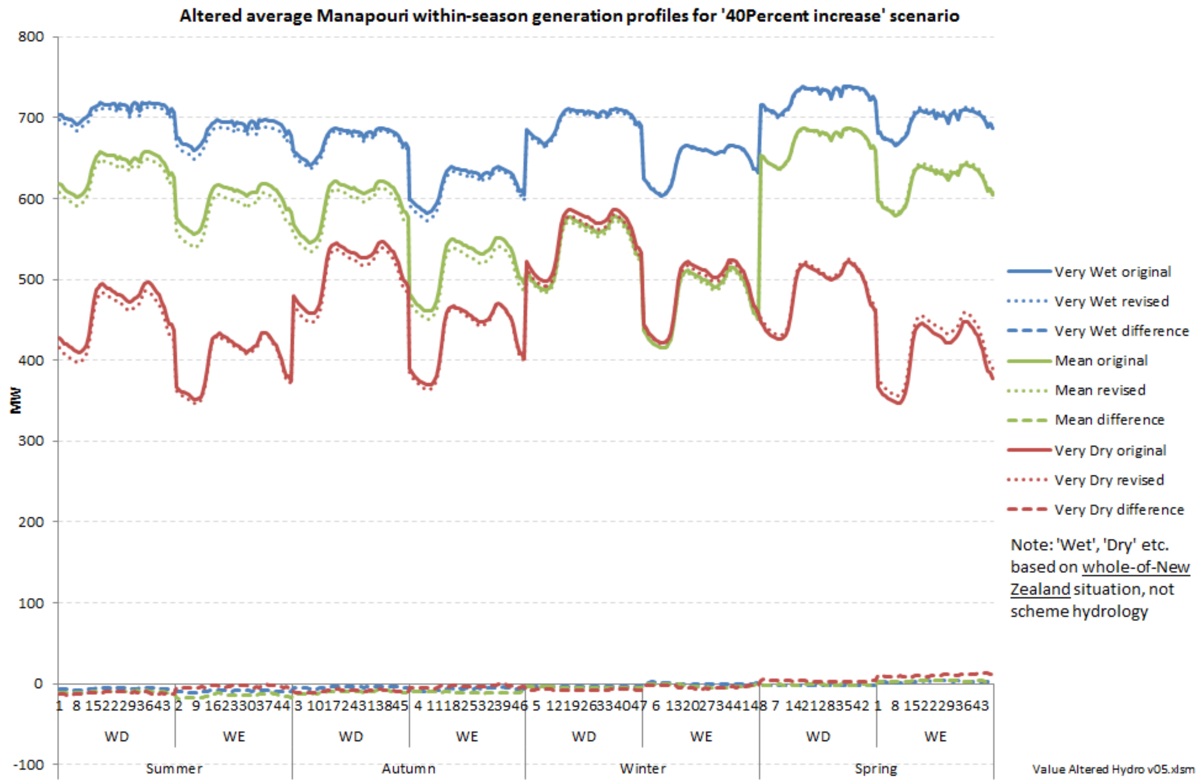
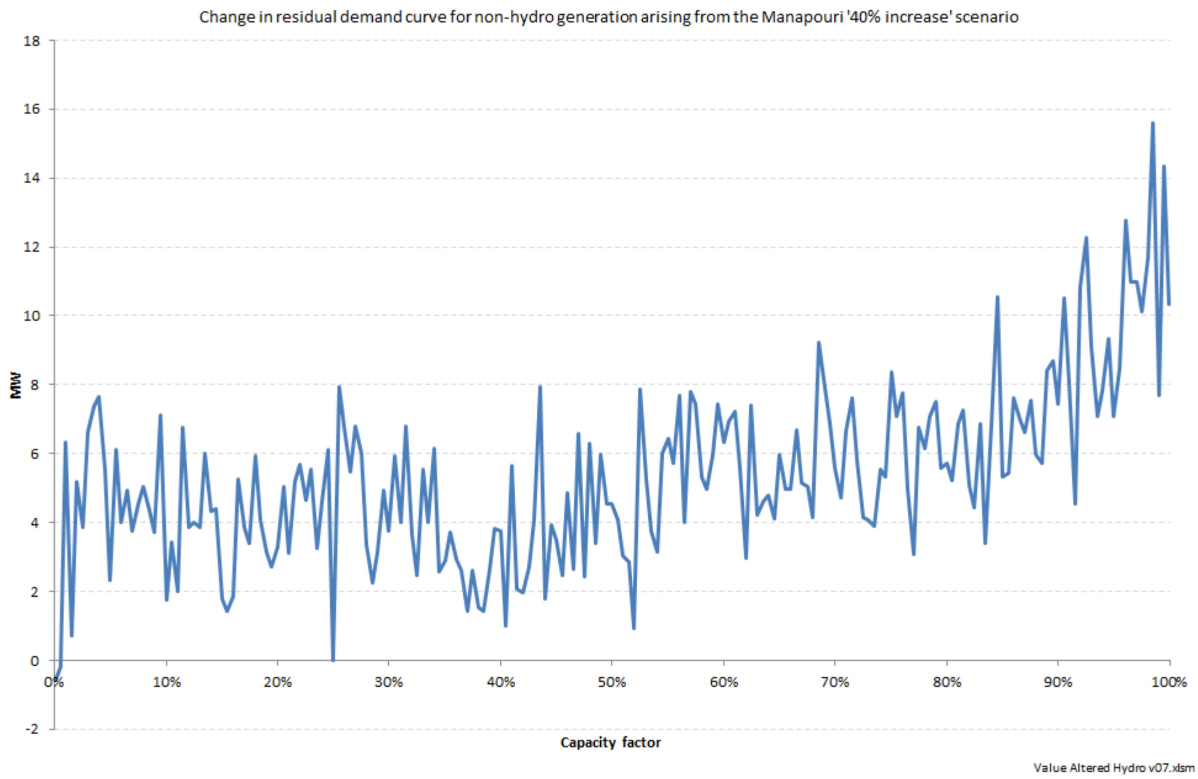
69 Average generation for each half hour in the 5 years ending 30 September 2012.

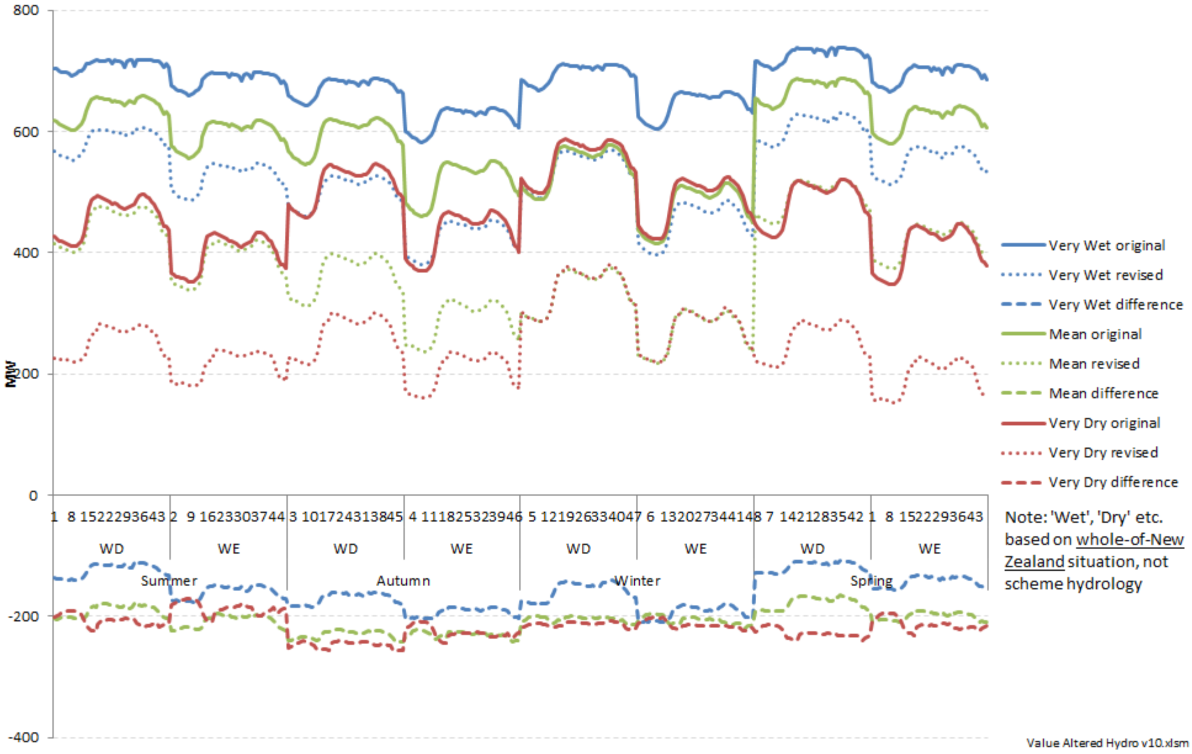


When considering the impact on the residual non-hydro demand duration curve, it would appear that the lost generation would predominantly be met by an increase in non-hydro baseload generation – as indicated by the much greater increase in demand for high capacity factor generation than for low capacity factor generation.

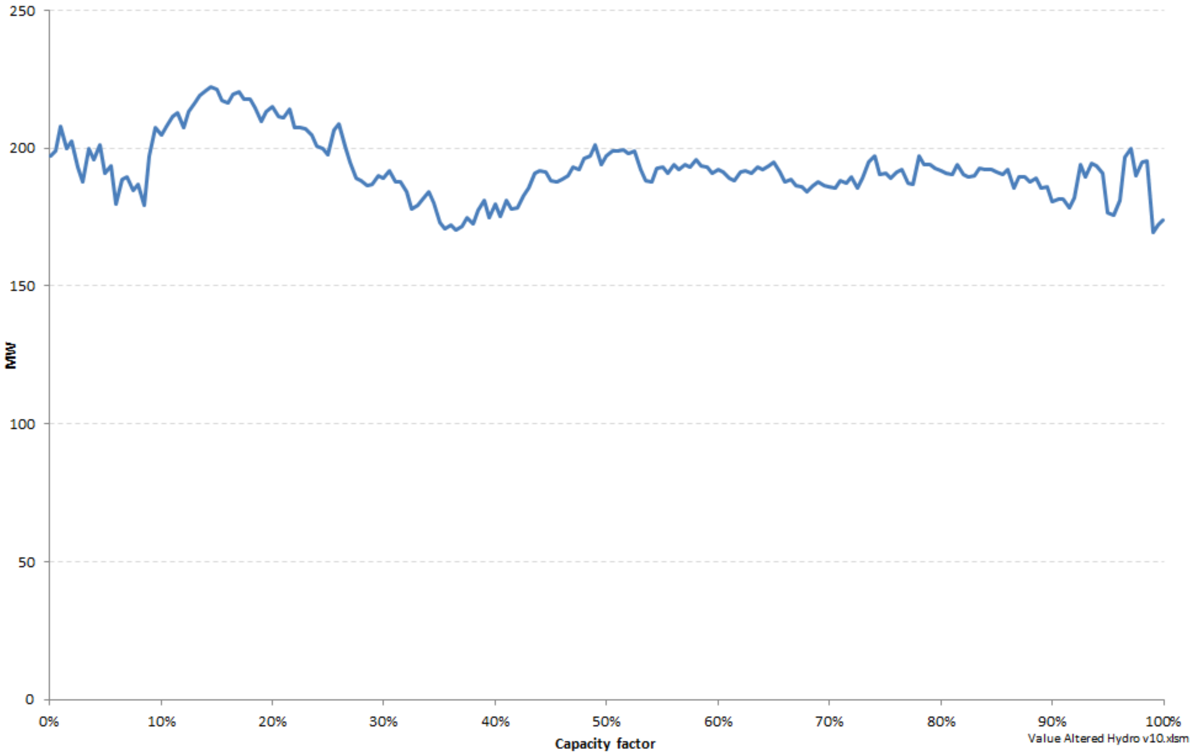


Meridian also considered some scenarios where the consented flows along the Waiau were set at a fixed percentage of natural MALF. The following figures show the results for the scenario whereby consented minimum flows are set at 80% of MALF. As can be seen, the % loss of generation is significantly greater. The shape of such losses suggests that, as with the 40% increase above current consented flows, the lost generation will predominantly be made up with increased non-hydro baseload generation.

Altered average Manapouri within-season generation profiles for '80% of MALF' scenario



Change in residual demand curve for non-hydro generation arising from the Manapouri '80% of MALF' scenario



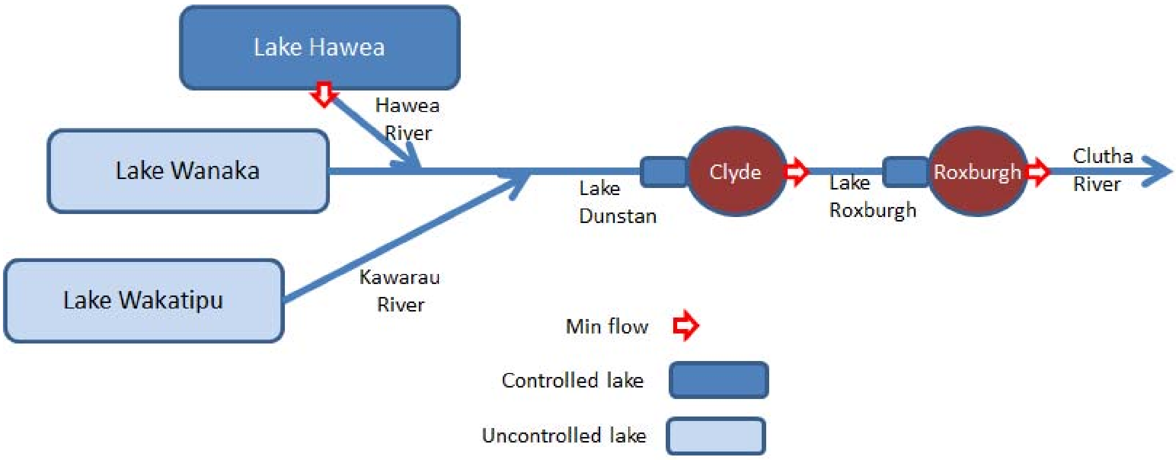
Clutha Hydro Scheme

Overview

The Clutha hydro scheme comprises two power stations (Clyde and Roxburgh) on the Clutha River with inflows fed from Lake Hawea, Lake Wanaka and Lake Wakatipu, plus a number of tributary rivers which flow into the Clutha and Kawerau Rivers. Lake Hawea is the only controlled seasonal storage lake.

Minimum flows requirements are imposed downstream of Roxburgh, Clyde, and for Lake Hawea outflows.

Figure 42: Schematic of Clutha hydro scheme



As is set out in the following tables, there are no consumptive flows associated with the Clutha scheme, but it has very little seasonal storage.

Table 8: Clutha generation data

Stations	MW Capacity	Approx Avg GWh pa		
		Consumptive flows	Natural flows	Total
Clyde	464		2,000	2,000
Roxburgh	320	-	1,600	1,600
Scheme	**784**	**-**	**3,600**	**3,600**

Table 9: Clutha storage data

Storage	Seasonal GWh	Intermediate GWh	% GWh (scheme) flows via storage
Lake Hawea	250		~ 13%
Lake Dunstan		~ 6	~99%
Lake Roxburgh		~ 1	100%

As noted, Lakes Wanaka and Wakatipu are uncontrolled storage

Table 10: Clutha flow data (cumecs)

	7DMALF[70]	Consented minimum flows
Hawea dam	29 (13.9 modified)	10
Clyde dam	215 (266 modified)	0 (night) 120 (day)
Roxburgh dam	221 (251 modified)	250 (lower if natural inflows less than 250)

Minimum flows are monitored on a 15 minute basis.

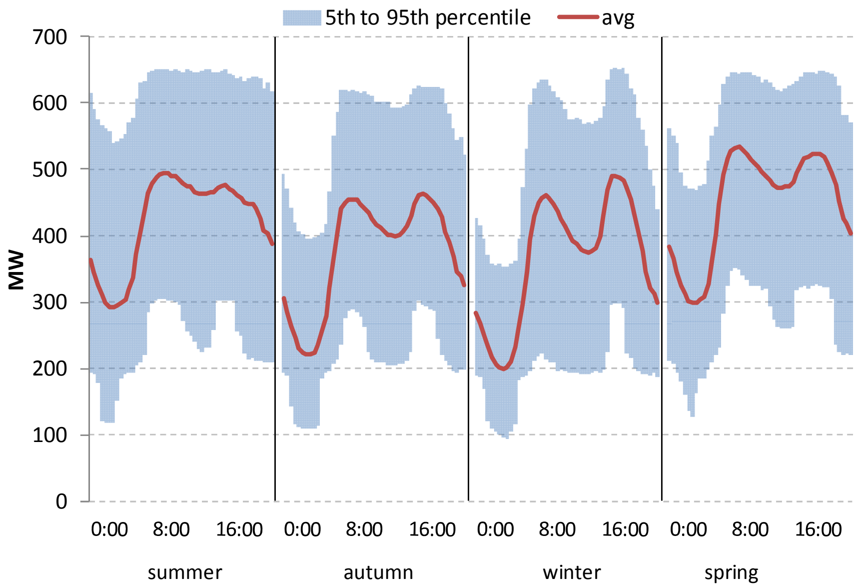
As can be seen, the minimum flows at the Roxburgh dam are already above natural (i.e. un-modified) minimum flows, and equal to the modified minimum flow levels. Prior to March 2007, Roxburgh minimum flows were 150 cumecs in winter and 100 cumecs in summer. As noted later, comparing the operation of the scheme before and after the change provides some insights into the implications of increasing minimum flows on the Clutha scheme.

Indicative flexibility

The Clutha scheme has limited seasonal storage capacity and generation is largely from uncontrolled inflows.

The chart below illustrates that the scheme has a reasonable amount of short term flexibility although to a lesser extent in spring and summer when inflows tend to be higher.

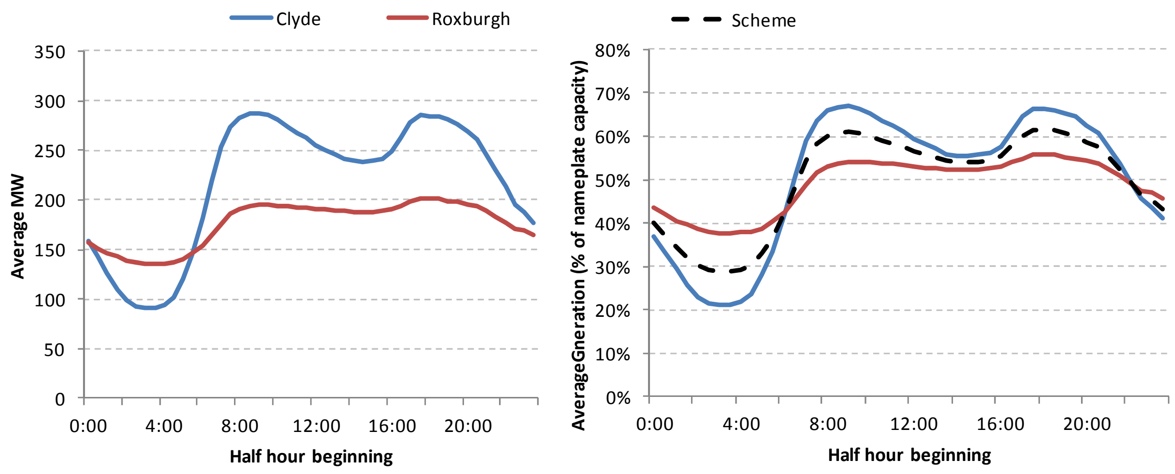
Figure 43: Clutha generation statistics by season



70 The main MALF values are shown for the un-modified river. The modified figures shown are the 7Day MALF figures after the man-made modifications have been in place.

The following charts highlights how the operation of Roxburgh power station is constrained by minimum flow requirements downstream and that intermediate storage enables greater short term generation flexibility at Clyde power station[71]. Note that because the minimum stable generation of one unit at Clyde is 70 MW (which corresponds to 140 cumecs), achieving a non-zero minimum flow of less than 120 cumecs can only be achieved by operating a unit at the 140 cumec level or by spilling past all units.

Figure 44: Average generation from Clutha stations



High level implications of altering minimum flows

Increasing minimum flows from Hawea and/or Clyde would impact on the flexibility of the Clutha's operation – both diurnally (i.e. increased generation at night at the expense of the more valuable day periods) and seasonally (i.e. reduced ability to store water to target more valuable winter months).

Increasing minimum flows at Hawea would also likely increase spill due to some such releases occurring at times when tributary inflows further down the scheme are at levels where Clyde and/or Roxburgh are facing inflows which are at or beyond their maximum capacity.

Increasing minimum flows downstream of Roxburgh would further reduce short term flexibility and affect the management of Lake Hawea storage (especially if combined with increased minimum flows from that lake).

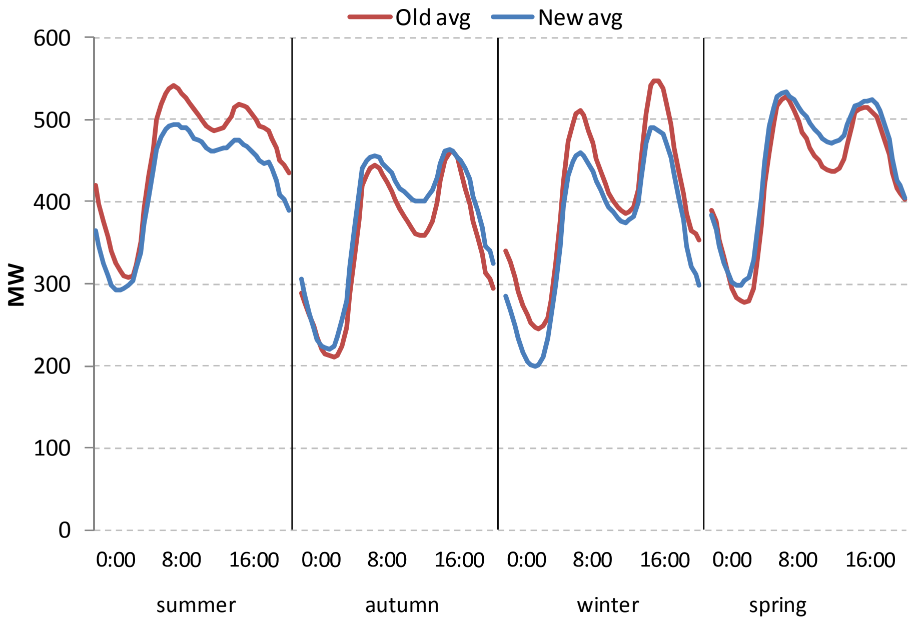
However, as noted above, minimum flow requirements at Roxburgh are already above natural levels. Accordingly, given the limited storage at Lake Hawea it would rapidly become infeasible to operate the scheme to achieve such increased minimum flows. Indeed this is recognised at the current consents whereby the minimum flows (which are measured every 15 min) are allowed to go below the consented minimum flow level (which is an average over 7 days), if such hourly inflows drop below this level.

As was noted above, Roxburgh minimum flows were only increased to the 7DMALF level in March 2007. Prior to that time, Roxburgh minimum flows were 150 cumecs in winter and 100 cumecs in summer. Comparing the actual operation of the scheme before and after the change provides some insights into the implications of increasing minimum flows on the Clutha scheme. This is illustrated in Figure 45 below which compares the average seasonal MW profiles shown previously (under the

71 Average half hourly generation for each station the scheme for the 2 years ending September 2012.

minimum current flow regime) to the seasonal averages under the lower minimum flow regime that was in place prior to 2007[72].

Figure 45: Impact of historical change in Clutha minimum flows



It can seen that on average the scheme was able to operate more flexibly prior to the increase in minimum flow requirements. For example, the red lines indicate that on average the scheme was previously better able to shift generation into higher value peak daily demand periods.

This effect is further illustrated in Figure 46 and Figure 47 which show that prior to March 2007, there was greater ability to shift generation from the lower demand night time period to higher value periods. The effect is most pronounced in winter when electricity supply is typically most valuable.

72 For the 6 years ending September 2006.

Figure 46: Clutha generation ratios for winter business days before and after increase in minimum flow limits[73]

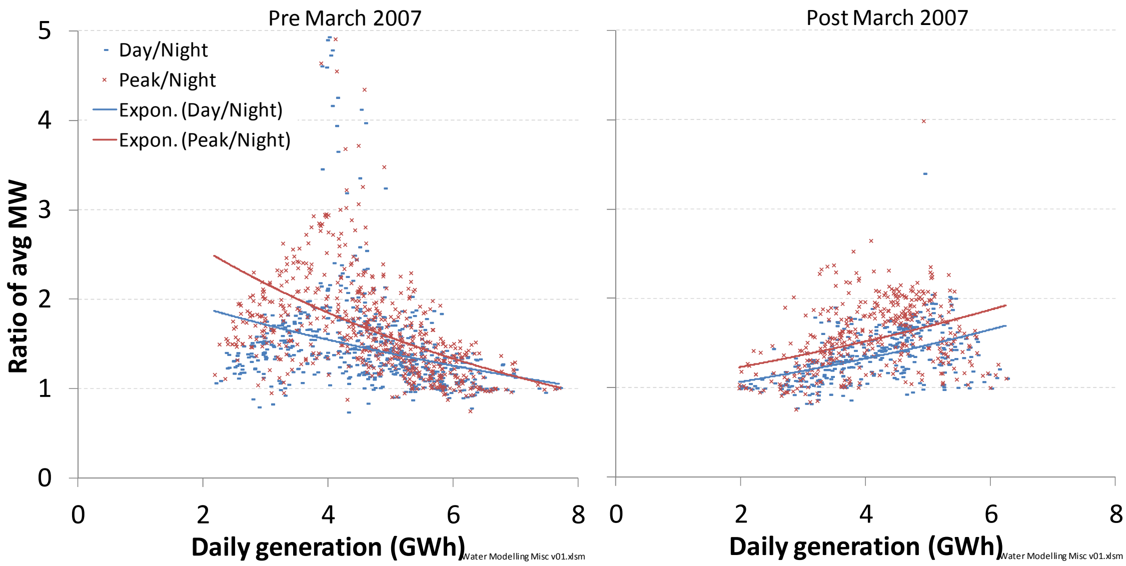
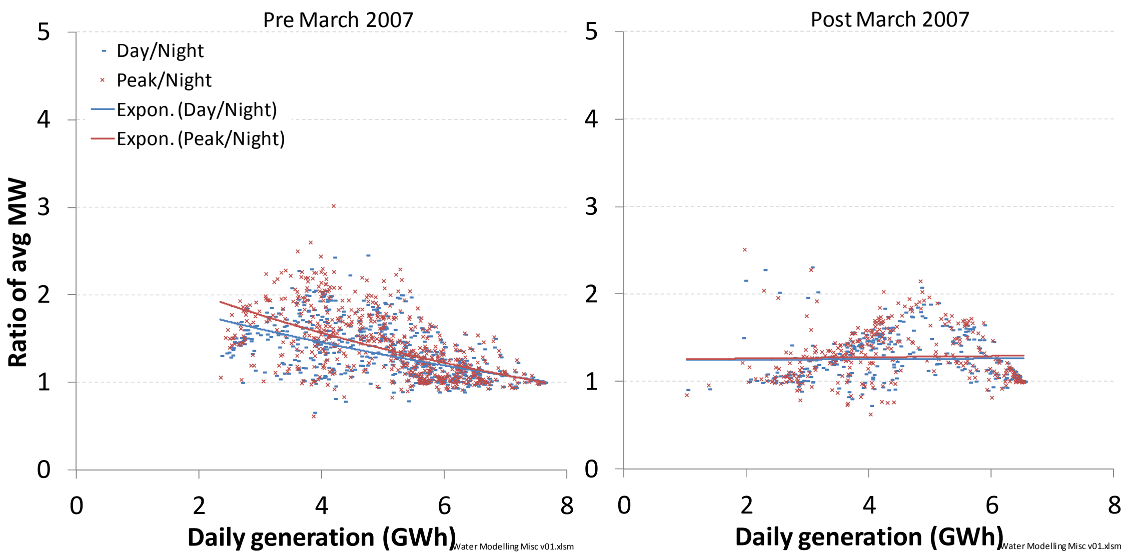


Figure 47: Clutha generation ratios for summer business days before and after increase in minimum flow limits



Results of Contact modelling

Contact provided half-hourly flow, generation and spill data for three historical years which represented, from the Clutha scheme's perspective, a Dry (2001), Average (2011), and Wet (1998) year.

73 A high ratio indicates that there was a greater quantity of Day or Peak generation relative to Night generation – i.e. the scheme has been able to sculpt its water into relatively high value periods. It appears that the distribution of such generating patterns has shifted Post March 2007 relative to Pre March 2007. In particular it appears that for days of relatively low generation (i.e. days with relatively low inflows) of approximately 2-5 GWh, the pre-March 2007 Clutha was able to sculpt such relatively low water into higher value periods more than post-March 2007. At very high generation levels (i.e. approaching 8 GWh in the day) the generation ratios tend to 1 for both pre- and post-March 2007 – i.e. the scheme is generating flat-out for 24 hours of the day.

Some fairly high-level modelling was undertaken by Contact and Concept to estimate the potential impact of increased minimum flows at Hawea and just below Clyde.

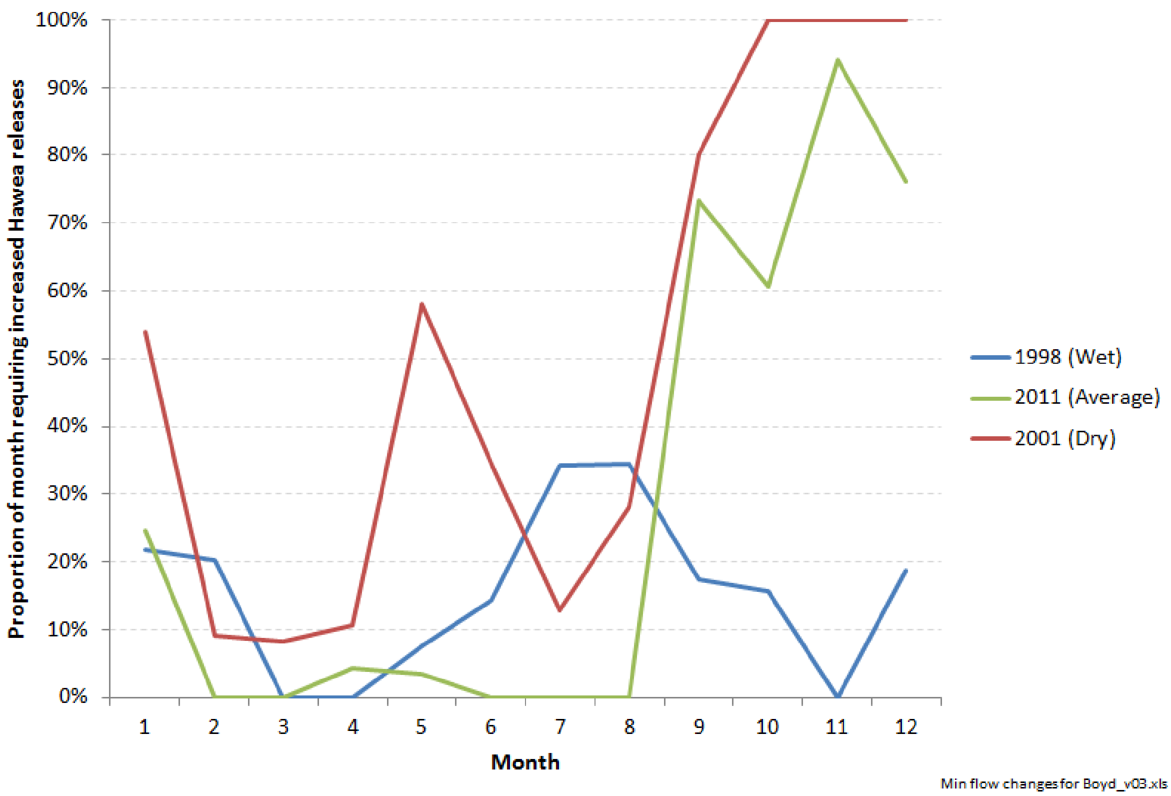
No modelling was undertaken to estimate the impact of raising minimum flows at Roxburgh because, as set out above, it would not be feasible to raise minimum flows further as they are already above natural minimum flow levels.

The modelling that was undertaken for considering increased minimum flows at Hawea simply looked at all time periods in the historical data series, and determined when Hawea releases would need to be increased in order to meet these new requirements.

The analysis revealed that the revised operating regime would result predominantly in altered Hawea releases on a seasonal basis, but minimal altered Hawea releases on a diurnal basis. This reflects the fact that when Hawea releases get to minimum levels they remain that way for sustained periods of a time on a 24/7 basis, rather than Hawea being operated such that releases are dropped to minimum levels overnight and then increased during the day.

The altered seasonal releases for the 40% scenario are shown in Figure 48 below.

Figure 48: Proportion of month requiring increased Hawea releases for the 40% increase in minimum flows scenario



Increasing Hawea flows in one month would mean they would be unavailable for subsequent months.

It is hard to infer, just from this limited sample, the general pattern of altered storage and release decisions that would occur from increased minimum flows at Hawea, and Contact did not undertake any modelling to simulate such decisions. However it is reasonable to conclude that there would be a shifting from higher value months to lower value months. In particular, it would be likely that there would be a shifting away from Winter months – which is where water is currently targeted – to Summer and shoulder months.

Accordingly, to get a feel for the scale of potential costs, the flexibility cost associated with increased Hawea releases was valued at the price difference between average winter spot prices, and average spot prices at all other times.

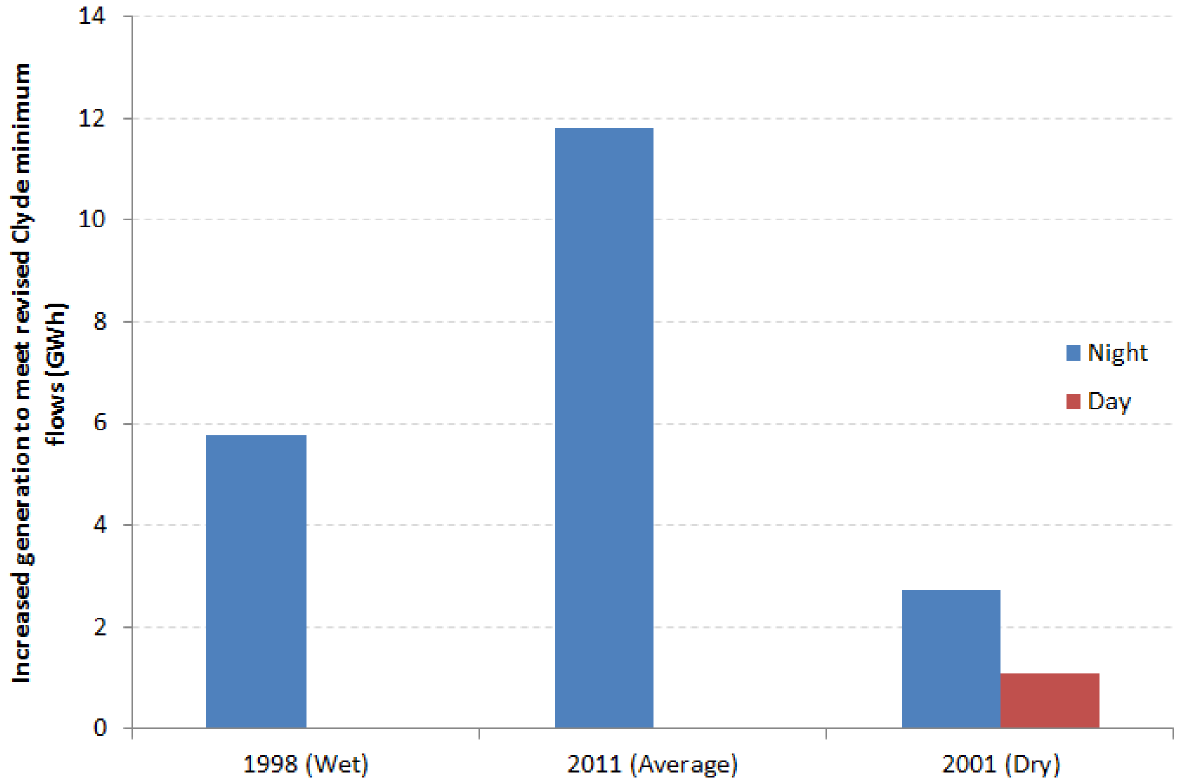
In addition to this impact of shifting generation from higher value periods to lower value periods, there would likely be increased spill arising from two phenomena.

The first is having to increase Hawea releases at a time where, due to major inflows further down the scheme, Clyde and/or Roxburgh are actually spilling water. This effect has been estimated by looking at the historical data series and summing all those periods where Hawea was at minimum releases levels but Clyde and/or Roxburgh were spilling. In the absence of any more dynamic modelling of such a phenomenon, it was assumed that the increased Hawea releases associated with an increase in Hawea minimum flows would result in increased Clyde and/or Roxburgh spill in direct proportion, with such lost generation being costed at the generation-weighted average of Clutha generation.

The second cause of spill would arise from having to operate Hawea more conservatively in order to meet higher minimum flow requirements in the event of a dry sequence as per the discussion in Appendix B. Contact did not do any modelling of this, so no estimate of the scale of potential impact could be undertaken.

With respect to increased minimum flows at Clyde the analysis calculated the quantity of increased GWh that would be required for those periods where flows at Clyde were below the revised minimum flow threshold. In doing so, it took account of the fact that it would not be possible to achieve a minimum flow associated with the scenarios, as this level would be below the minimum stable generation for a single machine. Accordingly the flow levels were set at the level associated with this minimum stable generation level.

As the following graph indicates, the increased generation occurred predominantly during night time periods.



Min flow changes for Boyd_v03.xls

The consequence of such increased generation overnight is that less water would be available at higher value times. In the absence of specific modelling of this phenomenon, the cost of the 'shifted' GWh was valued at the average price differential between day and night periods.

Tongariro Power Scheme (TPS)

Overview

The TPS is located in the headwaters of four major catchments (namely the Whanganui, Whangaehu, Moawhango, and Tongariro) and diverts water via a series of canals and tunnels through Rangipo and Tokaanu power stations, supplementing flows in the Tongariro River (which also has residual flows bypassing Tokaanu power station into Lake Taupo).

The Eastern Diversions flow through both power stations via seasonal storage at Lake Moawhango, whereas the Western Diversions only flow through the Tokaanu power station. Lake Rotoaira provides short term storage at Tokaanu power station. Not all of outflows from Rangipo go through Tokaanu as consented minimum flows of 16 cumecs are released down the Tongariro.

The flows diverted into the scheme account for around 20% of the water flowing into Lake Taupo and approximately 15% of the generation from the Waikato river power scheme.

Figure 49: Schematic of Tongariro Power Scheme

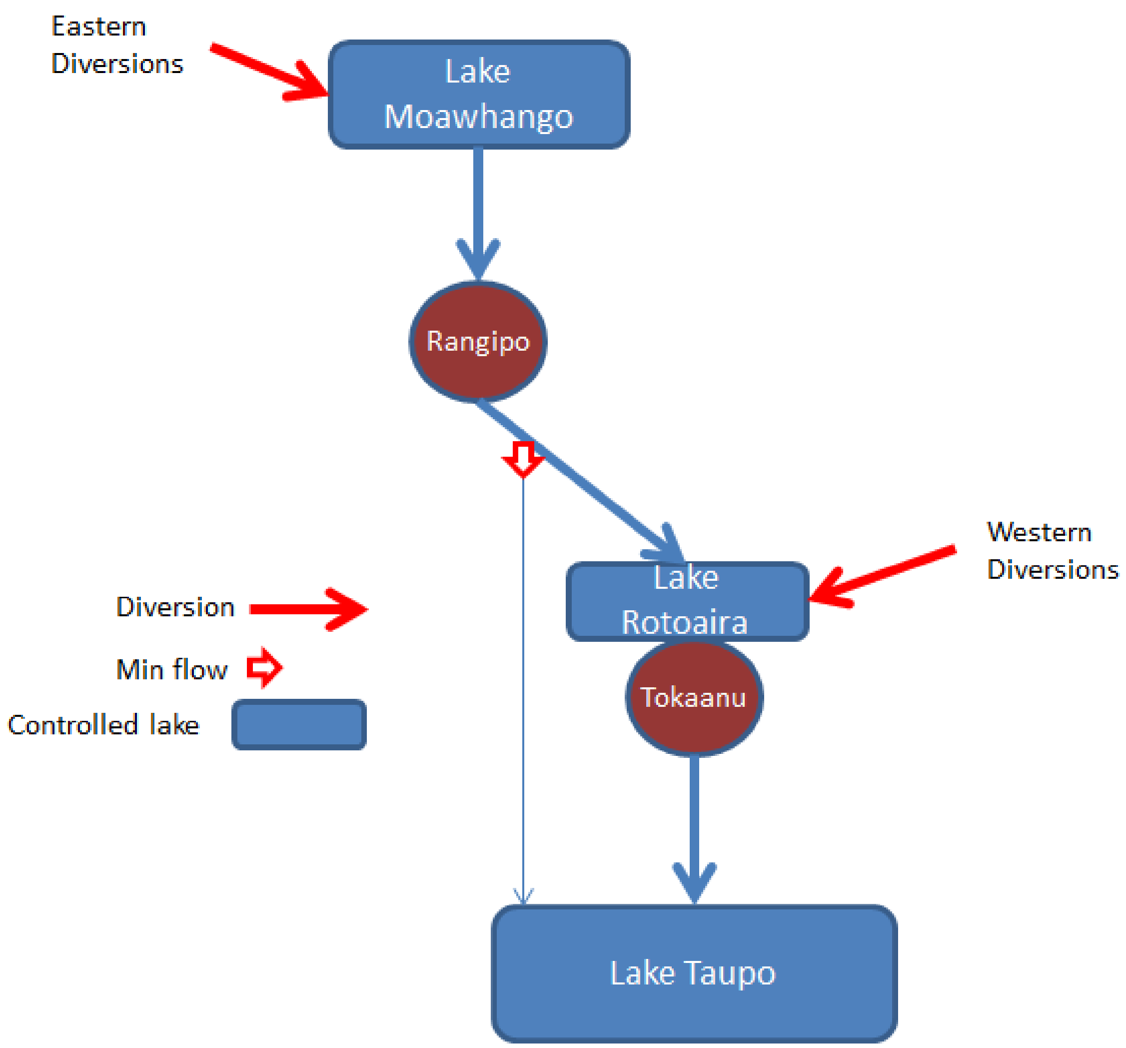


Table 11: TPS generation data

Stations	MW Capacity	Avg GWh pa		
		Consumptive flows	Natural flows	Total
Rangipo	120	228	332	560
Tokaanu	240	489	231	720
Scheme	**360**	**717**	**563**	**1,280**

Table 12: TPS storage data

Storage	Seasonal GWh	Intermediate GWh	% GWh (scheme) flows via storage
Moawhango dam	100		33%
Lake Rotoairo		11	100%

There are currently seven different points around the various diversions where Genesis Energy is required under its existing consents to achieve non-zero minimum flows. There are seven other rivers and streams where zero minimum flows are allowed under the consents.

Indicative flexibility

Tokaanu power station provides significant day to day flexibility, given intermediate storage in Lake Rotoaira, compared to Rangipo power station. The Moawhango dam provides limited seasonal storage capacity. This is compensated to some extent because the scheme's inflows are on average reasonably correlated with demand (compared to South Island hydro inflows).

The charts below illustrate these effects.

Figure 50: TPS generation statistics by season

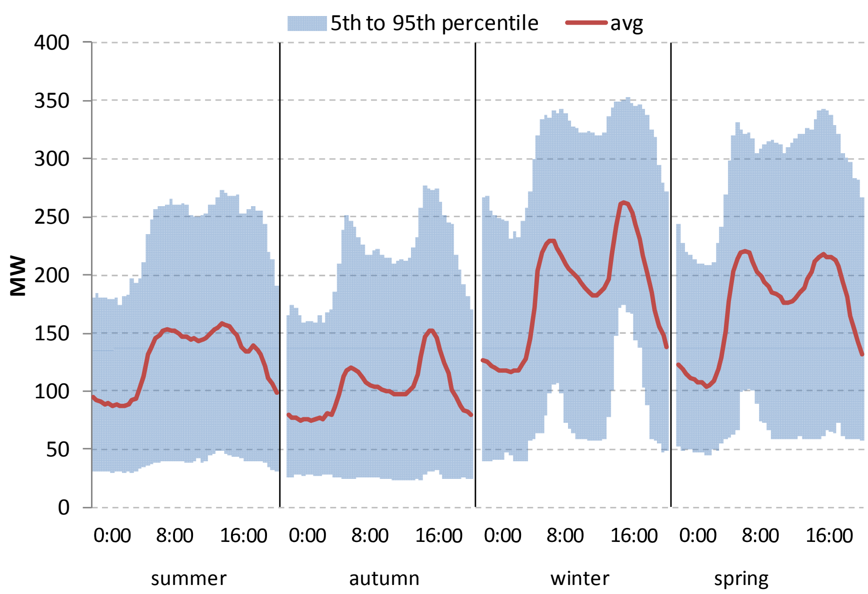
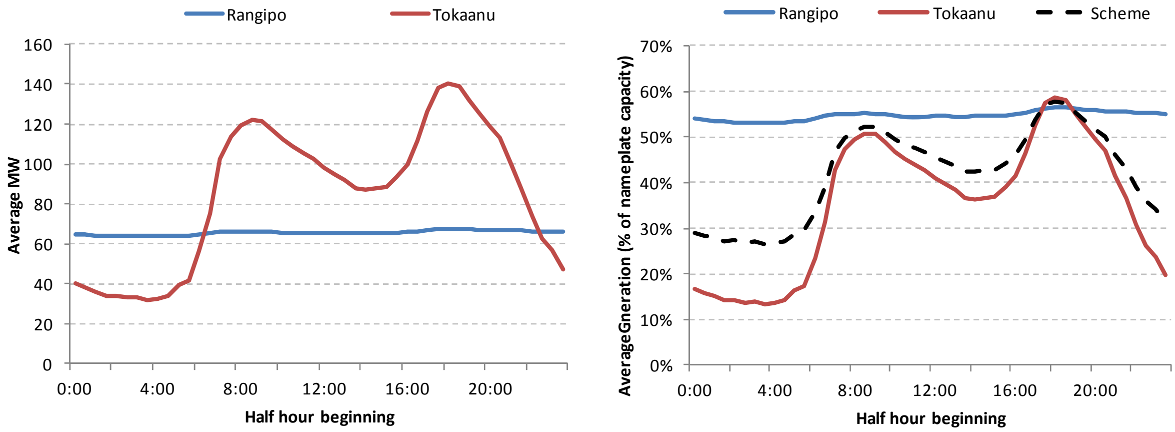


Figure 51: Average generation from TPS stations



High level implications of altering minimum flows

Reducing diversions into the scheme to maintain higher minimum flows elsewhere would reduce energy supply from the scheme. Reducing eastern diversions would affect generation from both Rangipo and Tokaanu power stations. Reducing western diversions would affect Tokaanu generation.

There would also be downstream impacts on Lake Taupo and Waikato River flows. This would reduce Waikato Hydro generation (as discussed further below) and could complicate the management of Lake Taupo, constraining seasonal generation flexibility, in order to meet minimum lower Waikato River flows.

This could also have flow on river related constraints on Huntly Power stations.

Results of TPS modelling

Genesis Energy undertook extensive analysis of the impact of altering minimum flows at the many different diversion points around the scheme for three scenarios:

- 10% increase on existing minimum flows.
- 40% increase on existing minimum flows
- Setting minimum flow requirements at 80% of 7DMALF

For those diversion points where existing flows are allowed to be zero under current consents, the minimum flow for the first two scenarios was set at 10% or 40%, respectively, of 7DMALF)

The results of the analysis provided to Concept was in the form of a series of monthly cumec and GWh values for 38 historical inflow years (namely 1970 to 2007). Each month was assigned to one of the five hydrological quintiles (i.e. Very Dry through to Very Wet) based on whole-of-New Zealand hydrology, rather than TPS-specific hydrology.

No modelling was undertaken by Genesis Energy regarding altered within-month / within-day generating patterns. Accordingly, Concept converted the monthly values provided by Genesis Energy into within-month profiles using historical observed generating profiles from the period 1998 to 2011. This process used observed historical profiles consistent with the monthly GWh values produced by Genesis Energy. For example, if a projected level of generation for July for one of the historical inflow years was X GWh, the within-month profile used by Concept was based on the historical July month whose monthly generation was closest to X GWh. This was intended to produce within-month generation profiles which were broadly consistent with the projected GWh for a particular month. However, it should be recognised that this is a relatively simplistic process and will introduce greater degrees of uncertainty into the analysis. No analysis has been undertaken to determine whether this may systematically over- or under-estimate the impact.

In terms of the average loss of generation, the results of the analysis are set out in the table below

Scenario	Average loss of generation	
	GWh	Percentage
10% increase	61	4.0%
40% increase	239	15.6%
80% of 7DMALF	241	15.7%

With regards to the loss of flexibility, it would appear that there is not any systematically greater loss of generation during dry periods than wet periods.

However, it is hard to draw conclusions with regards to the loss of within-month / within-day flexibility as it is based on a simple factoring approach using historical profiles rather than a proper optimisation. Doing a number of cross-checks it would appear that the valuation approach may be under-estimating the loss of within-day flexibility. However, the level of under-estimation is not considered to be of a scale that would give rise to the estimated costs being radically different to those shown in the results.

Waikato Hydro Scheme

Overview

The Waikato hydro scheme comprises 8 power stations[74] on the Waikato River from Aratiatia to Karapiro and includes control gates at the outlet of Lake Taupo. There are minimum flow requirements at the Lake Taupo control gates and downstream of Lake Karapiro.

Approximately 20% of the water flowing into Lake Taupo is consumptive (from water diverted into the TPS) representing approximately 15% of overall generation from the Waikato hydro stations.

[74] Treating Maraetai A and B power stations as a single station.

Figure 52: Schematic of Waikato hydro scheme

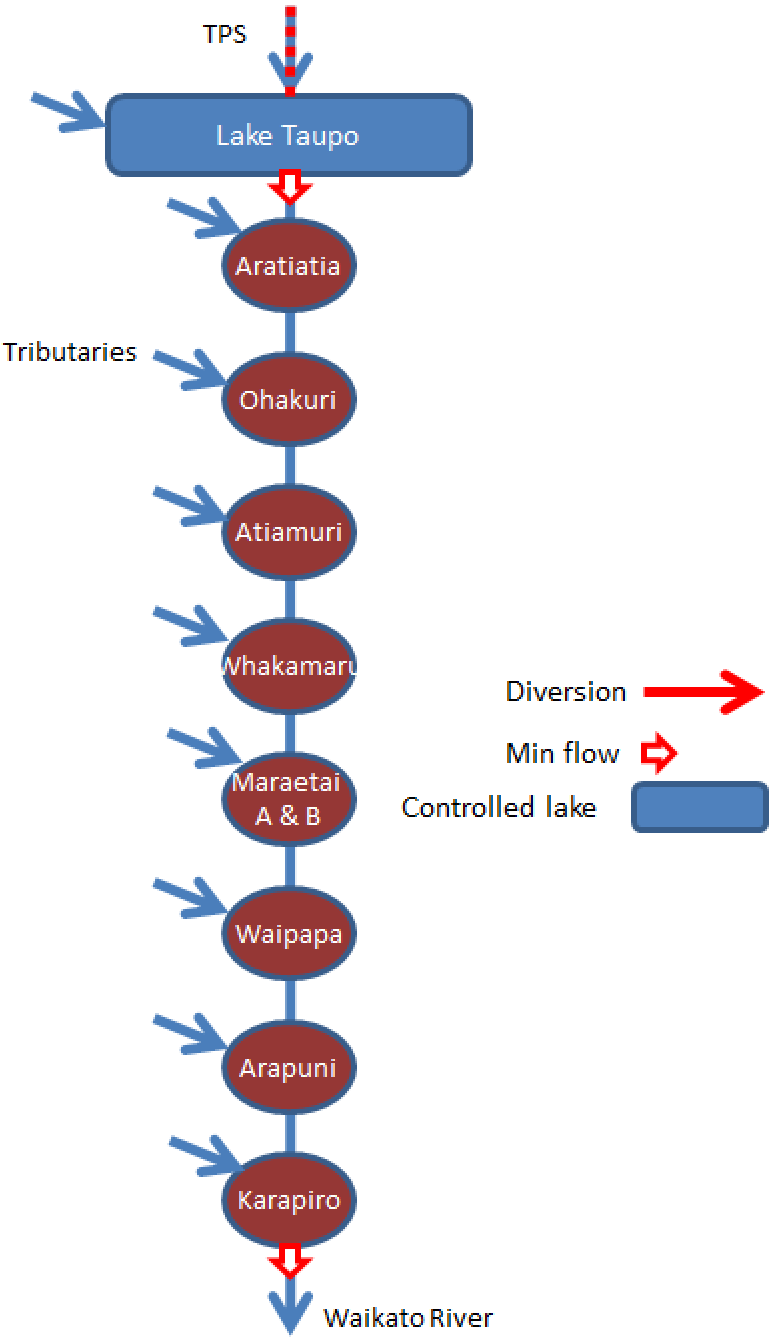


Table 13: Waikato hydro scheme generation data

Stations	MW Capacity	Approx Avg GWh pa		
		Consumptive flow*	Natural flow	Total
Aratiatia	78	65	270	334
Ohakuri	106	73	334	406
Atiamuri	74	48	240	288

Whakamaru	98	77	415	492
Maraetai	360	128	758	886
Waipapa	54	34	212	246
Arapuni	182	121	764	884
Karapiro	96	67	455	521
Scheme	**1,048**	**613**	**3,448**	**4,057**

**Tongariro diversions*

Table 14: Waikato hydro scheme storage data

Storage	Seasonal GWh	Intermediate GWh	Storage as % of GWh flow through
Lake Taupo	~ 500 - 560*		17%
Lake Aratiatia		0.5	0.01%
Lake Ohakuri		8	0.21%
Lake Atiamuri		1.6	0.05%
Lake Whakamaru		5.8	0.19%
Lake Maraetai		2.5	0.10%
Lake Waipapa		0.2	0.01%
Lake Arapuni		2.3	0.16%
Lake Karapiro		0.9	0.17%
Scheme	**500 - 560**	**21.8**	

**Varies depending on time of year (lower Jan – Mar)*

Table 15: Waikato hydro scheme flow data (cumecs)

	7DMALF	Consented minimum flows
Releases from Lake Taupo	94	50m^3/s*
Waikato River below Karapiro dam	151	140 to 150 cumecs

** determined as a 30 minute rolling average (unless required to maintain flows from Karapiro between 140 and 150 cumecs, Lake Taupo is below minimum level).*

Indicative flexibility

The Waikato hydro scheme has very good short term flexibility given intermediate storage, particularly at Lakes Ohakuri and Whakamaru. However, the scheme can be relatively complex to manage on a day to day basis given some bottle necks/ limited storage in parts of the river and large flow delays along the scheme. With inflows reasonably well correlated to demand, and with Lake Taupo storage, seasonal supply is also reasonably matched to requirements. The operation of the scheme is constrained by the need to maintain minimum flows downstream of Karapiro power station.

The following chart illustrates the considerable flexibility of the Waikato hydro scheme.

Figure 53: Waikato hydro scheme generation statistics by season

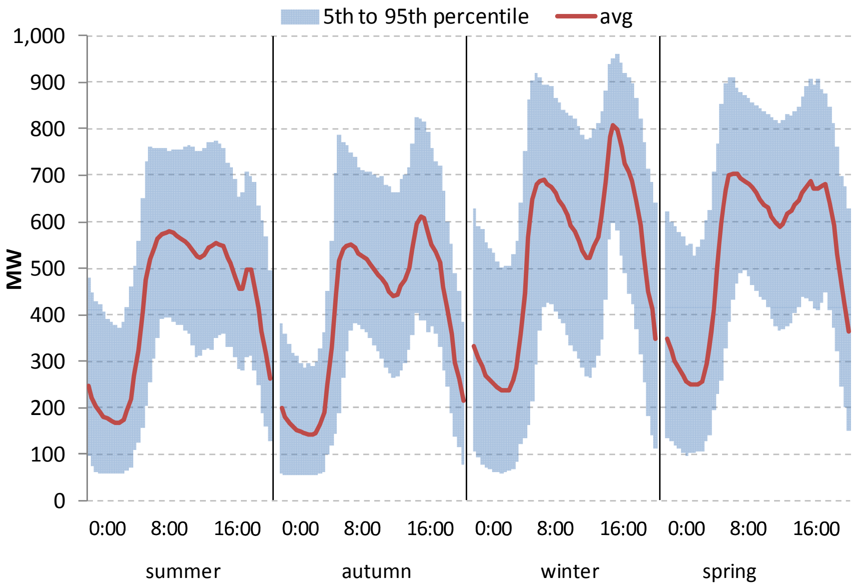
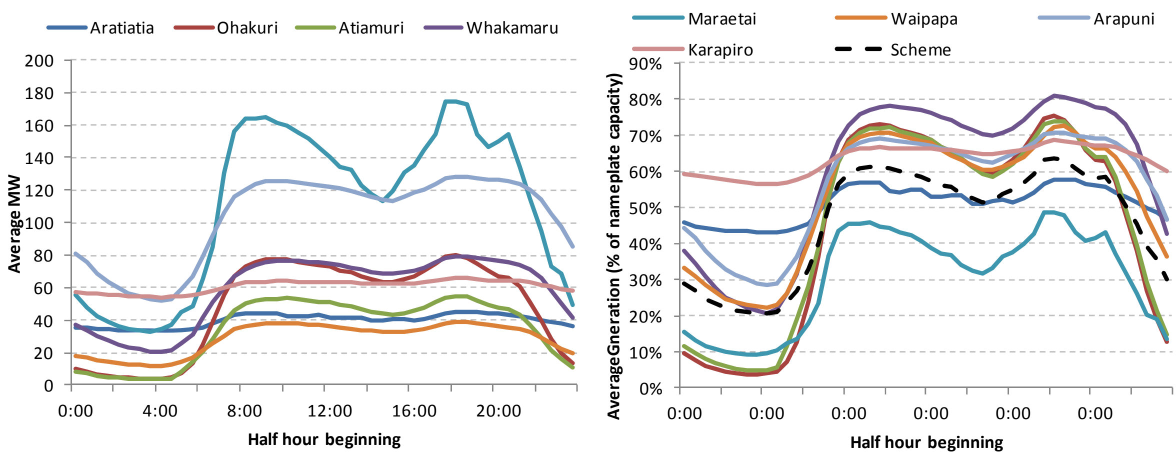


Figure 54: Average generation from Waikato hydro scheme stations



High level implications of altering minimum flows

Altering minimum flows in the TPS by diverting less water into that scheme would reduce energy supply from the Waikato hydro scheme and complicate the management of Lake Taupo in order to manage Karapiro minimum flows. Thus, not only would there be an absolute loss of GWh, but there would be a loss of flexibility resulting in hydro generation being shifted from more valuable periods to less valuable periods.

Increasing minimum flows at Lake Taupo, Aratiatia and Karapiro would further constrain the operation of the scheme noting that the scheme provides a significant amount of seasonal and especially short term flexibility. Any additional spill would also reduce energy supply.

Increasing minimum flows from Karapiro could have the offsetting benefit of reducing temperature related constraints on Huntly power station to the extent river flows at Huntly would not otherwise be as high.

Results of Mighty River Power modelling

Mighty River Power provided detailed simulations of hourly generation, flows and lake levels at each Waikato hydro station representing from its perspective historical dry (2003), average (2007) and wet (2004) hydrological years. This included base case simulations with current minimum flow limits from Taupo (50 cumecs), Aratiatia (50 cumecs) and Karapiro at (148 cumecs) and simulations with minimum flow limits increased by 5% and, except for 2007 inflows, 15%.

The other generators provided simulations of their schemes with 10% and 40% increases in minimum flow requirements. It has therefore been difficult to assess the impact of increasing Waikato hydro minimum flow limits in a manner consistent with other hydro schemes.

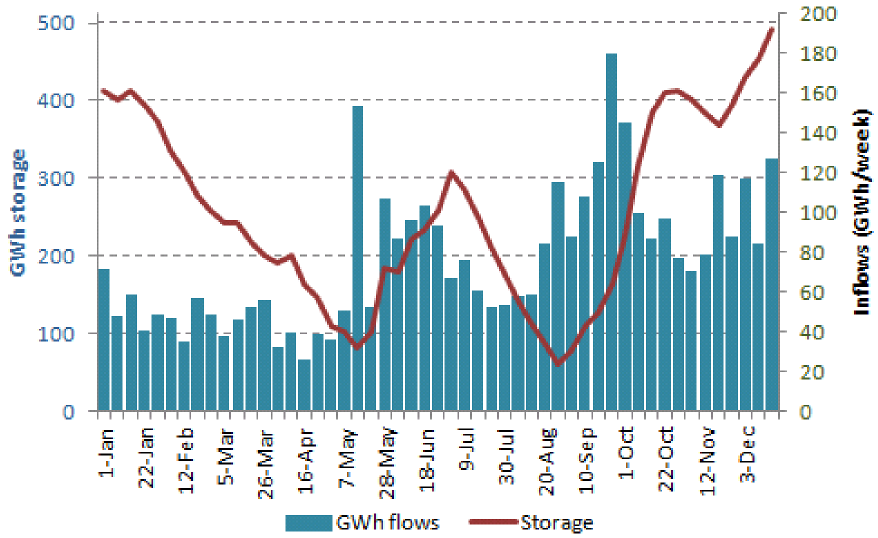
Further, while the Waikato hydro simulations were very detailed in respect of the river chain downstream of Lake Taupo, they assumed historical Taupo levels and outflows. i.e. potential impacts of increasing minimum Waikato hydro flow limits on the management of Lake Taupo storage were not modelled.

From the simulations provided, at face value it appears that intermediate storage within the Waikato hydro chain of stations is sufficient to accommodate minimum flow limits being increased by 15% without material loss of GWh or flexibility – although there is some shifting of generation from day to night periods.

However, that is based on perfect hindsight modelling, historical Lake Taupo starting levels and releases, and a sample of just three flow years, all of which suggests that the modelling undertaken by Mighty River is likely to *under*estimate the impact of increased minimum flows.

Perfect hindsight modelling probably understates the potential impact on short term flexibility (and potentially on the risk of spilling water). In practice, limited amounts of storage along the river, significant flow delays along the chain (in excess of 24 hours) and uncertain tributary inflow forecasts mean a degree of conservatism is necessary in managing the scheme within minimum flow limits.

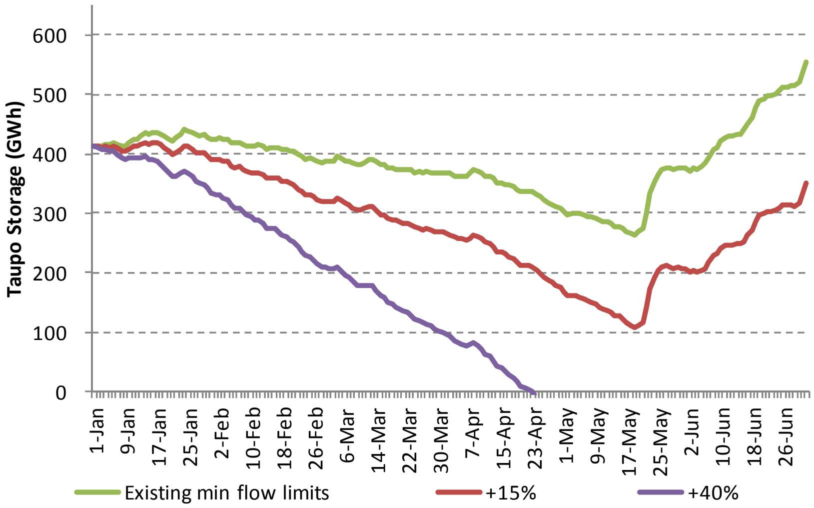
Of the three flow year scenarios, 2003 was a seen as a dry year. As illustrated below, there was a dry period until May with another short spell in July.



The Mighty River Power modelling indicated that if Waikato hydro minimum flow limits were increased by 15%, some additional releases from Lake Taupo storage would have been required at times in the 2003 inflow scenario. This suggests that raising minimum flow limits by 15% would affect the management of Lake Taupo, increasing the need to store more water to cover increased minimum flow requirements during dry periods. Increasing minimum flow requirements by 40% would have a more significant impact on the management of Lake Taupo storage, and potentially on Mighty River Power's ability to meet the increased minimum flow requirement.

It is difficult to assess these effects without detailed modelling. However, it is possible to gain some insights. For example, relatively simple modelling by Concept indicates that it would not be feasible to increase minimum flows to 40% for 2003 inflows, as the increased releases from Taupo would eventually drain the lake to below the minimum consent level. This is illustrated in the following figure

Figure 55: Projected Lake Taupo storage levels based on 2003 inflows for varying minimum flow requirements (Taupo and Karapiro)

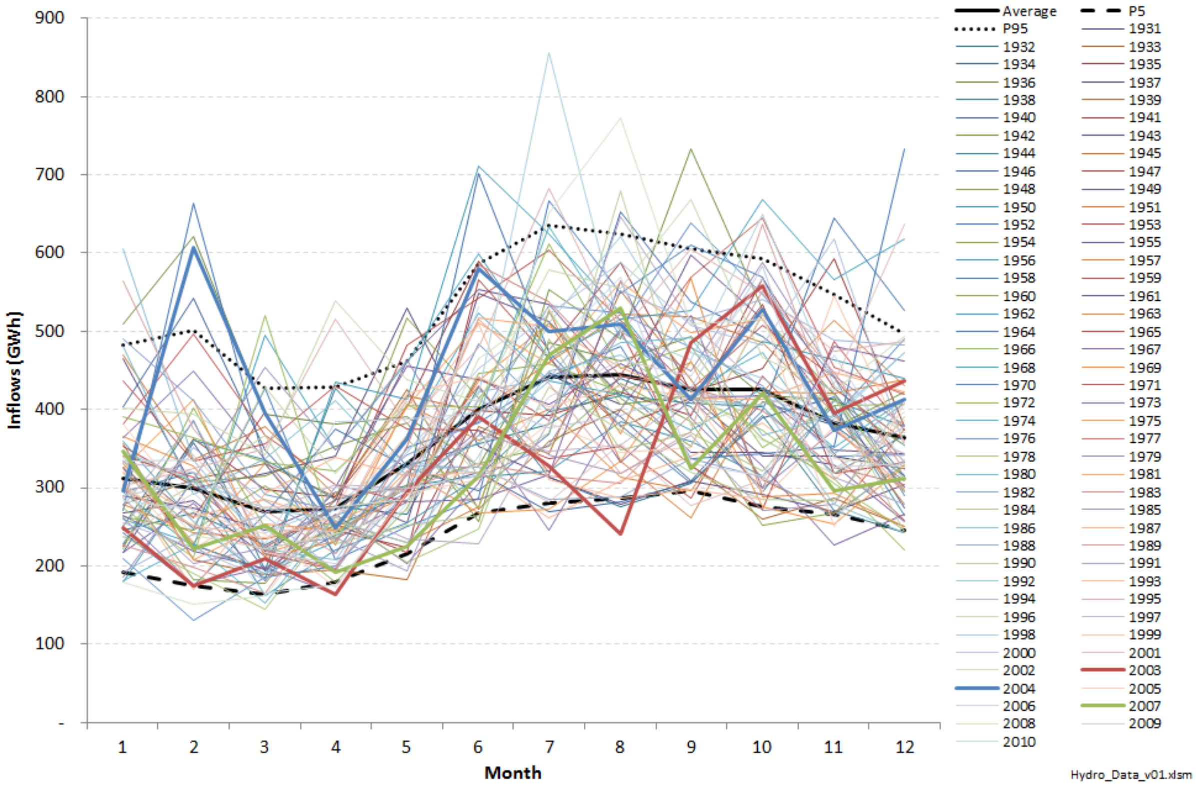


Inflows in 2004 and 2007 (the other two years for which Mighty River Power undertook analysis) were higher over the early part of the year and increased minimum flow requirements would have in theory imposed less constraints on the management of Taupo and a 40% increase in minimum flows could have been accommodated – at least using this perfect hindsight framework.

In practice, inflows cannot be predicted accurately, especially over longer periods, and the risk of dry spells and the ability to maintain minimum flow requirements would have a major influence on Lake Taupo storage and release decisions with Mighty River being required to operate the lake more conservatively as per the discussion in Appendix B.

Figure 56 below gives an indication of the range of seasonal inflows for the Waikato scheme from the years 1931 to 2010.

Figure 56: Historical monthly inflows for the Waikato scheme



Source: Concept analysis based on Electricity Authority data

Given the range of possible inflow futures for the following six month period at any moment in time, higher minimum flow requirements will require Taupo storage to be operated more conservatively.

A consequence of maintaining storage higher to cover potential dry spells is a greater risk of spill in wet periods. These effects cannot be quantified without detailed modelling which takes account of changes in the management of Lake Taupo, including evaluation over a larger sample of inflow years.

Further, for some of the historical inflow sequences, it is likely to become infeasible to maintain Lake Taupo storage levels for minimum flow requirements substantially below the 40% level which proved infeasible for the 2003 sequence.

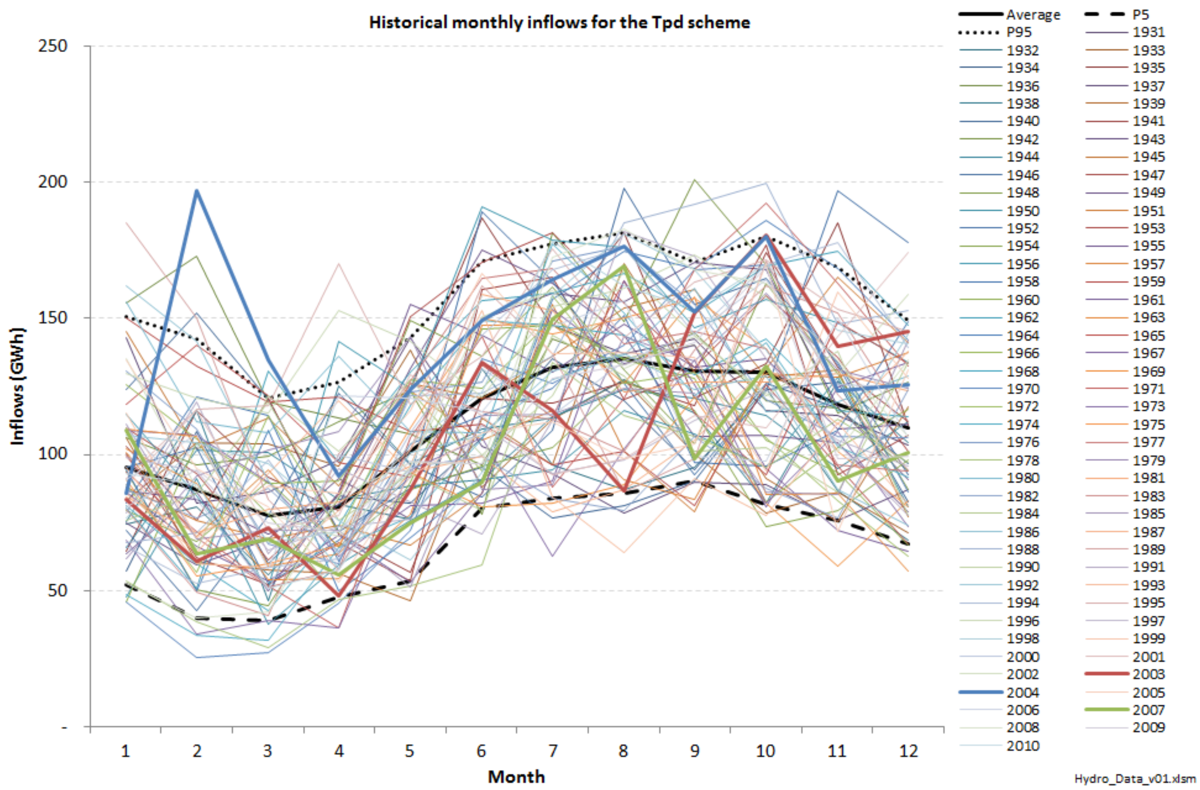
In summary, based on the analysis provided it appears that:

- For relatively low increases in minimum flows (i.e. ≤ 5%), intermediate storage provides a reasonable amount of flexibility to manage increased minimum flow requirements without substantially altering Taupo release requirements. The main impact of such increased minimum flows would be a shifting of some daytime generation to night-time.
- As minimum flow requirements increase, there would be progressively greater impacts on Taupo storage and release decisions. In particular, it would likely require increased conservatism in storage decisions, especially over the higher value winter and spring months, in order to maintain minimum flows during the summer months where inflows tend to be lowest. This change in storage and release decisions would have two impacts:
  - A shifting of water (generation) from higher value winter / spring months to lower value summer months; and
  - Increased spill and flood risks from needing to maintain Lake Taupo at higher levels.

- Increases in minimum flows beyond a certain point would become infeasible for some drier inflow sequences, requiring either the revised minimum flow requirements or consented Lake Taupo levels to be breached..

It is not possible to quantify such impacts without undertaking detailed modelling which simulated the impact of altered minimum flows on Taupo storage and release decisions.

Loss of water from the TPS would compound these issues. While overall GWh losses due to TPS flow losses, and the timing of such losses, are relatively easy to estimate, the timing of such losses and their effect on Waikato hydro flexibility would require detailed modelling, including Lake Taupo. However, it is clear that any loss of TPS water would compound the effects of increasing minimum flows within the Waikato hydro scheme.



The table below estimates the impact on the Waikato scheme in terms of lost water from the TPS due to increased minimum flows relating to the TPS scheme:

Scenario	Average loss of generation	
	GWh	Percentage
10% increase	62	1.5%
40% increase	101	2.5%
80% of 7DMALF	145	3.6%

These estimates were derived by simply multiplying the lost cumecs entering into Taupo (as reported by Genesis Energy via its modelling) by the Cumec / MW conversion ratios for the eight generators on the Waikato chain. This is likely to be a conservative estimate given that it takes no account of increased Taupo spill arising from the need to alter Taupo more conservatively.

Waipori hydro scheme

Overview

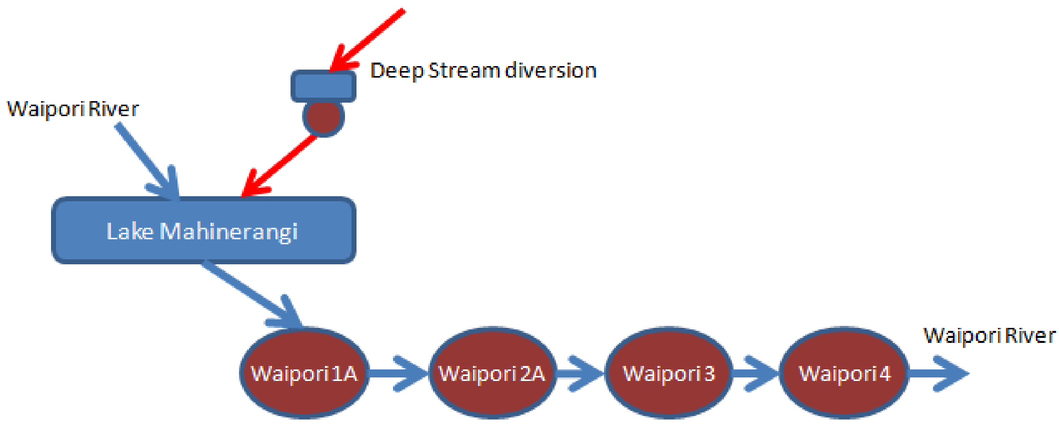
The Waipori hydro scheme, near Dunedin, consists of four power stations on the Waipori river: Waipori 1A (10MW), Waipori 2A (58MW), Waipori 3 (7.6MW) and Waipori 4 (8MW).

The Waipori river forms in the Lammerlaw mountains. It flows into Lake Mahinerangi, an artificial lake that acts as the reservoir for the scheme. Water also flows into Lake Mahinerangi via a diversion from Deep Stream that incorporates 6MW of generating capacity.

Water flows from the lake down a naturally formed steep gorge (the river drops 165 metres in only four kilometres) through the four power stations. The lake provides limited storage for around 9 months of the year.

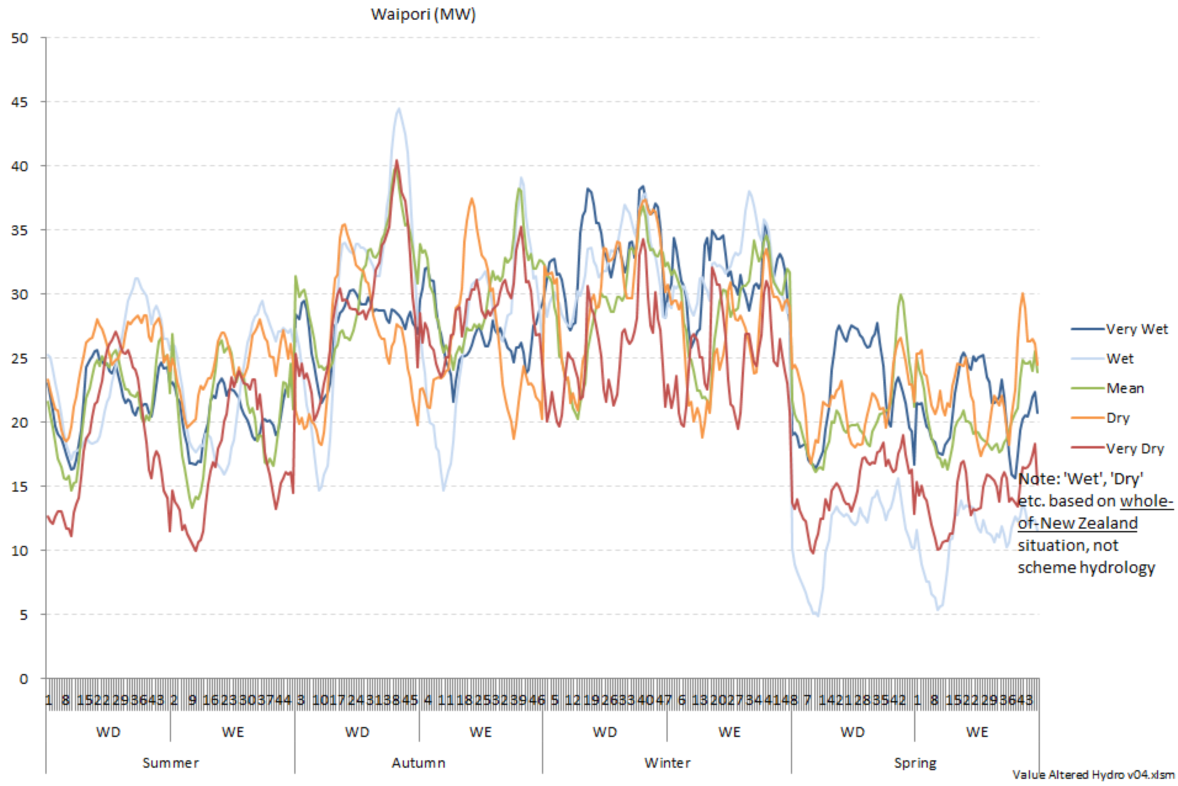
The scheme has a total average annual output of 220 GWh.

Figure 57: Schematic of Waipori hydro scheme



As is indicated by the following figure, the storage at Lake Mahinerangi enables Waipori's generation to be targeted on a within-day basis away from night periods and towards day and peak periods. Further the seasonal pattern of the Waipori scheme's inflows are positively correlated with the seasonal pattern of demand, enabling it to achieve materially higher generation in the Winter rather than in Summer. There also does not appear to be a strong correlation between New Zealand dry and wet periods and Waipori dry and wet periods.

Figure 58: Historical average pattern of Waipori generation for the period 1980 to 2012



Trustpower modelling of impact of altered minimum flows

The results of the modelling exercise undertaken by Trustpower were supplied in the form of quarter-hour generation profiles for every hour of the day for the historical years 1980 through to 2012 (except for Branch which was for 1989 to 2012). Such generation profiles were supplied for the base scenario (i.e. with existing minimum flow requirements), and for six different scenarios:

- Three scenarios which modelled the minimum flow requirements being increased above current levels by 5%, 10% and 40%; and
- Three scenarios which modelled the minimum flow requirements being set at 5%, 40% and 80% of natural MALF.

This large quantity of data[75] was summarised to produce average half-hourly generation profiles for a weekday and weekend for each of the four seasons for each of the 33 historical years.

These generation profiles were summarised further through averaging the 33 historical years to deliver generation profiles for five hydrology year types. As set out in section 3.2 above, each season for the historical years 1980 to 2012 was assigned to a *New Zealand* hydrology quintile ranging from Very Wet to Very Dry.

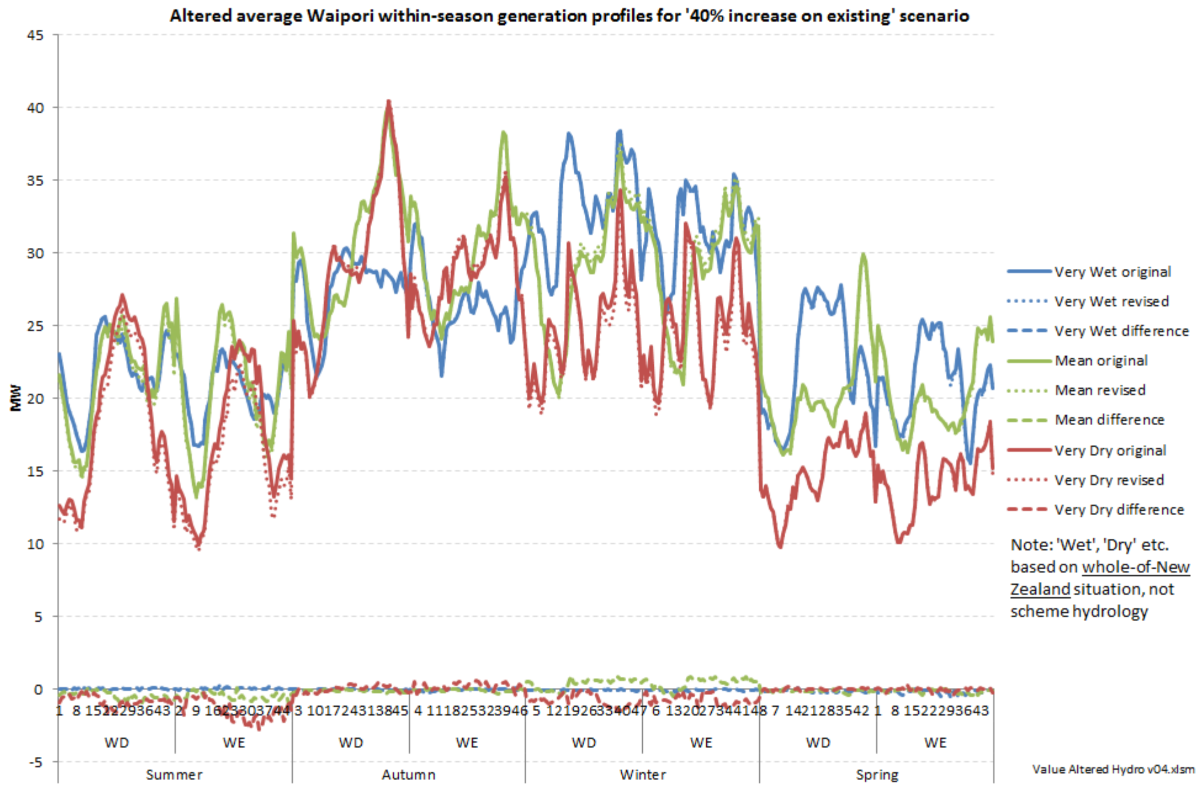
The table below illustrates the absolute GWh loss of generation from the scheme for the different scenarios.

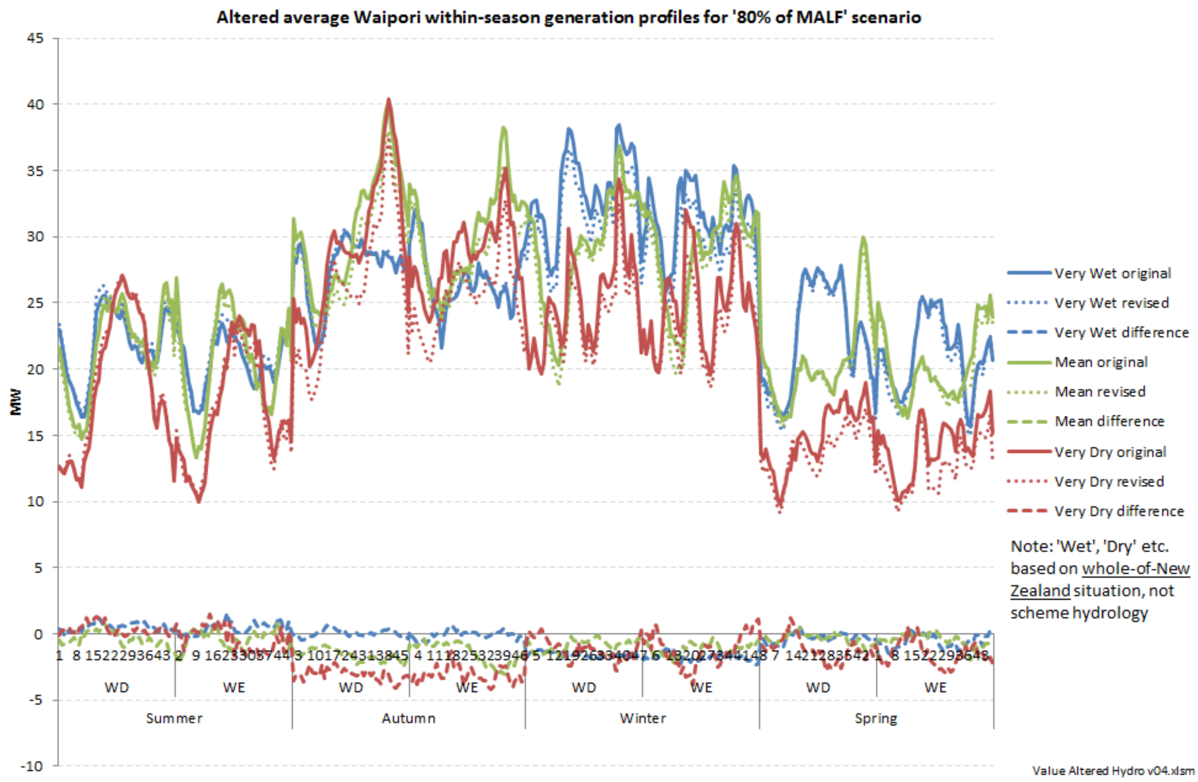
5% increase on existing	0.05%
10% increase on existing	0.07%
40% increase on existing	0.60%
5% of MALF	0.00%

[75] 96 quarter-hours * 365 days * 33 years * 7 scenarios = 8,094,240 data points for each scheme.

40% of MALF	1.82%
80% of MALF	3.41%

As the following graphs indicate, the pattern of such losses is not predominantly in any one season or period for the different scenarios. Accordingly, it is likely that a significant proportion of such lost generation will be made up by increased non-hydro baseload generation.





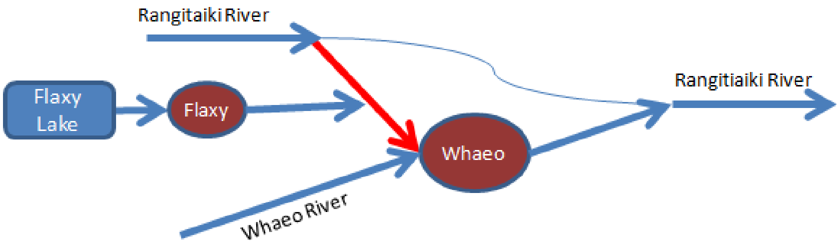
Wheao hydro scheme

Overview

The Wheao hydro scheme is a run-of-river scheme that diverts water from the upper Rangitaiki River in the Bay of Plenty, through the Rangitaiki canal. The water then flows through the Whaeo power station, and in to the Whaeo River. The scheme is supplemented with water from the Wheao River and Flaxy creek.

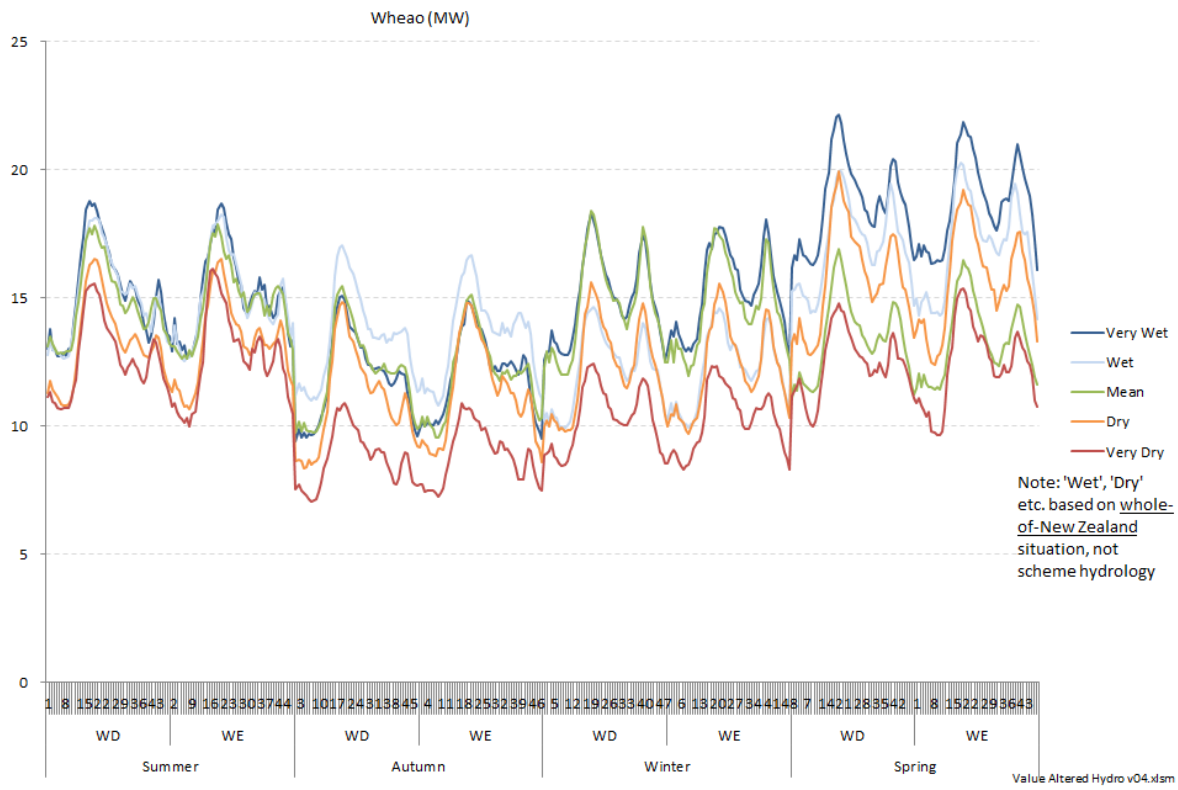
The scheme uses two generators at the Whaeo powershouse, delivering 12MW each, with a further 2.1MW at the upstream Flaxy powerhouse. It generates a combined 111 GWh of electricity annually.

Figure 59: Schematic of Whaeo hydro scheme



As the following figure shows, the intermediate storage enables the Wheao generation to be sculpted into high demand periods on a within-day basis, but has no seasonal capability, and very limited day-to-day storage capability (as indicated by the fact that weekend generation is only marginally lower than weekday generation).

Figure 60: Historical average pattern of Wheao generation for the period 1980 to 2012

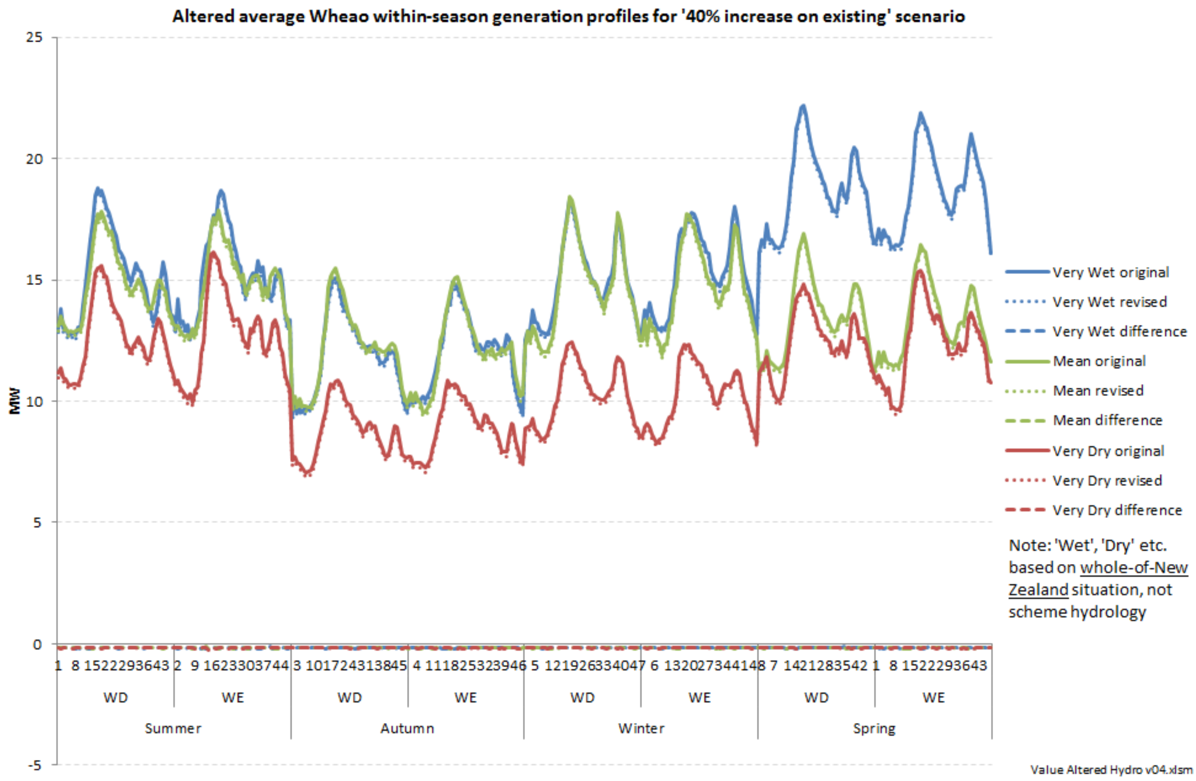


Trustpower modelling of impact of altered minimum flows

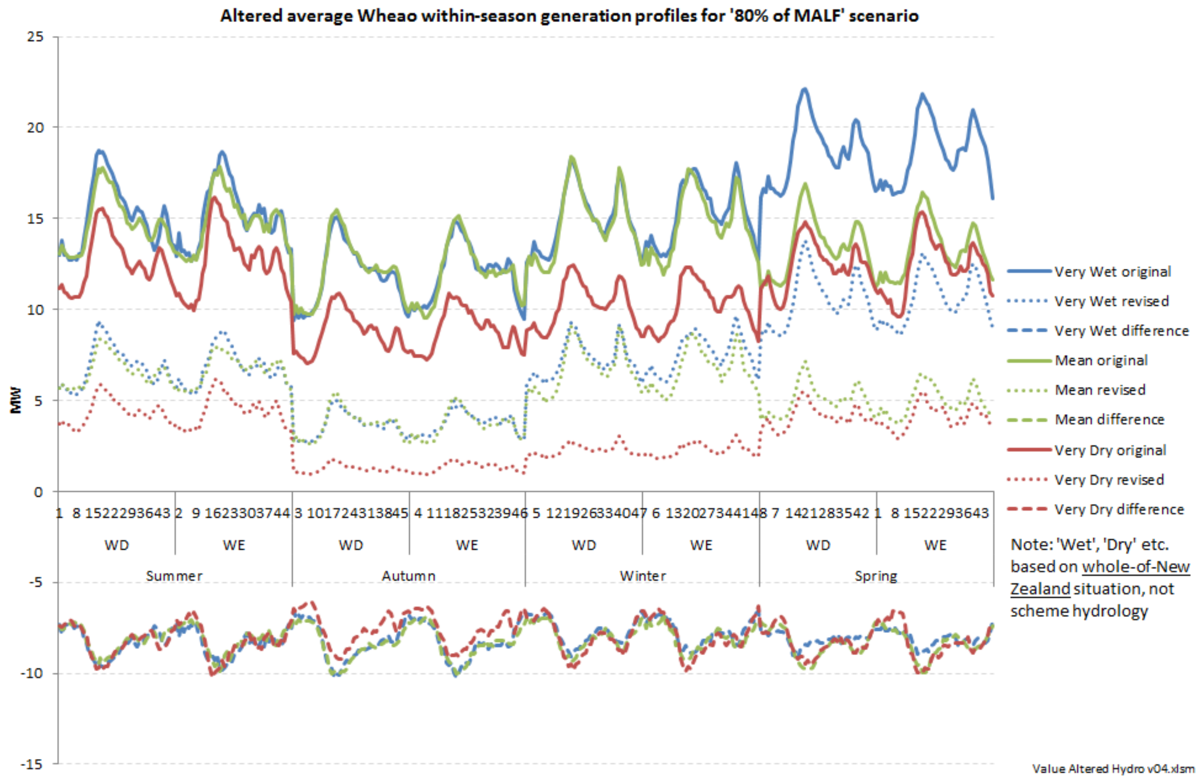
The following table indicates the scale of generation loss associated with the different scenarios.

Scen_name	% loss of generation
5% increase on existing	0.16%
10% increase on existing	0.31%
40% increase on existing	1.25%
5% of MALF	1.15%
40% of MALF	28.83%
80% of MALF	60.19%

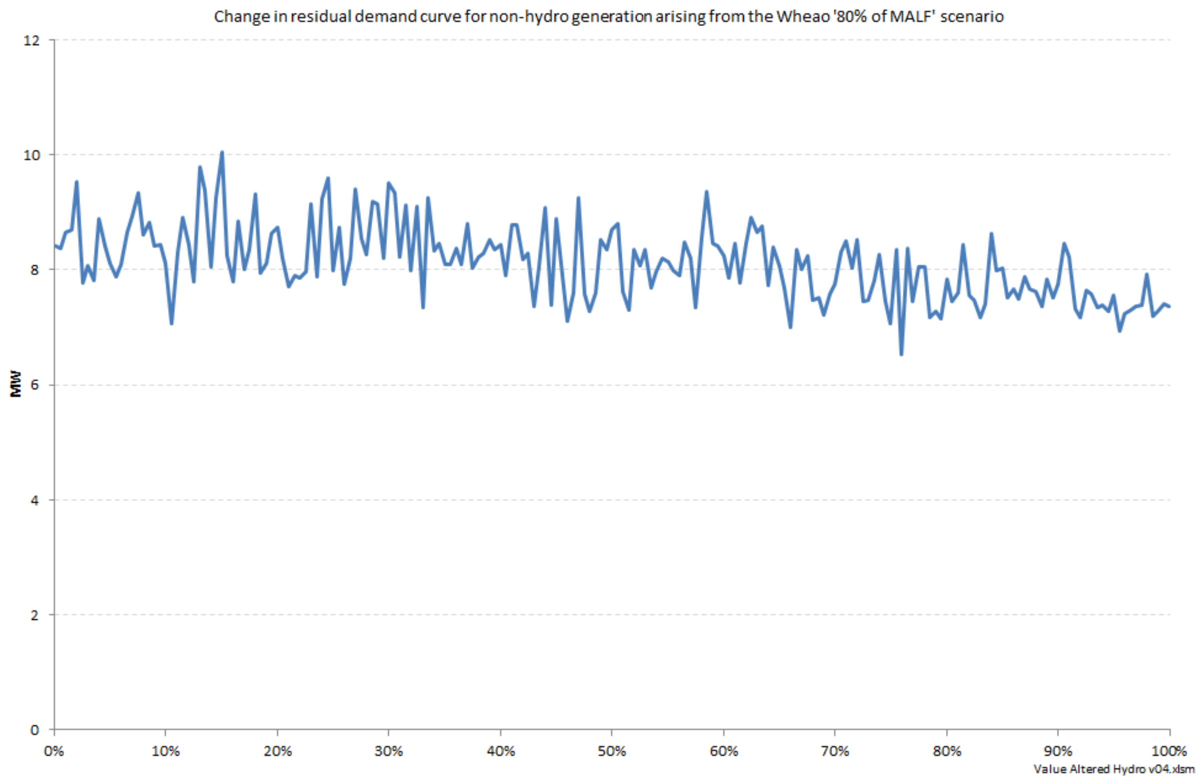
As the following figure shows, the modelling indicates there will be a relatively minor impact from increasing existing minimum flow requirements by 40% above current levels, and that such an impact would be relatively evenly spread across all periods.



However, as shown in the following diagram, for significant losses of water associated with the 80% of natural MALF scenario, the Wheao scheme would also lose some of its ability to sculpt water within-day to morning and evening peaks.



However, as the following diagram illustrates, the majority of this lost generation will likely be met by an increase in non-hydro baseload generation, with only a relatively small increase in the requirement for non-hydro peaking generation.



Branch hydro scheme

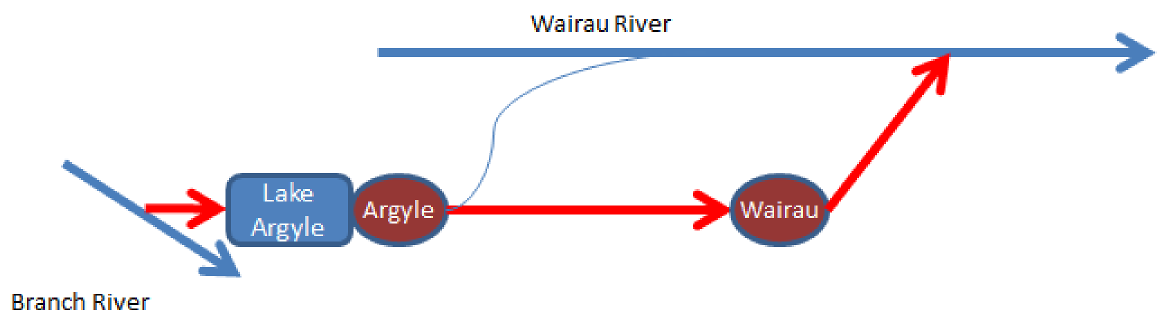
Overview

The Branch River hydro scheme is a run-of-river scheme with daily storage, situated on the Branch River in Marlborough. The Branch River is a tributary of the Wairau. It is dammed several kilometres upstream of its natural confluence with the Wairau. Water is passed via a canal in to a headpond known as Lake Argyle which provides a few hours of storage. From here it feeds the Argyle power station, and then along another canal to the Wairau power station before being discharged to the Wairau River.

The two power stations have a combined total capacity of 11 MW, and average annual output of 53 GWh.

TrustPower plans to expand the scheme by adding another 72 MW of capacity at Wairau. This project has been consented but is currently on hold.

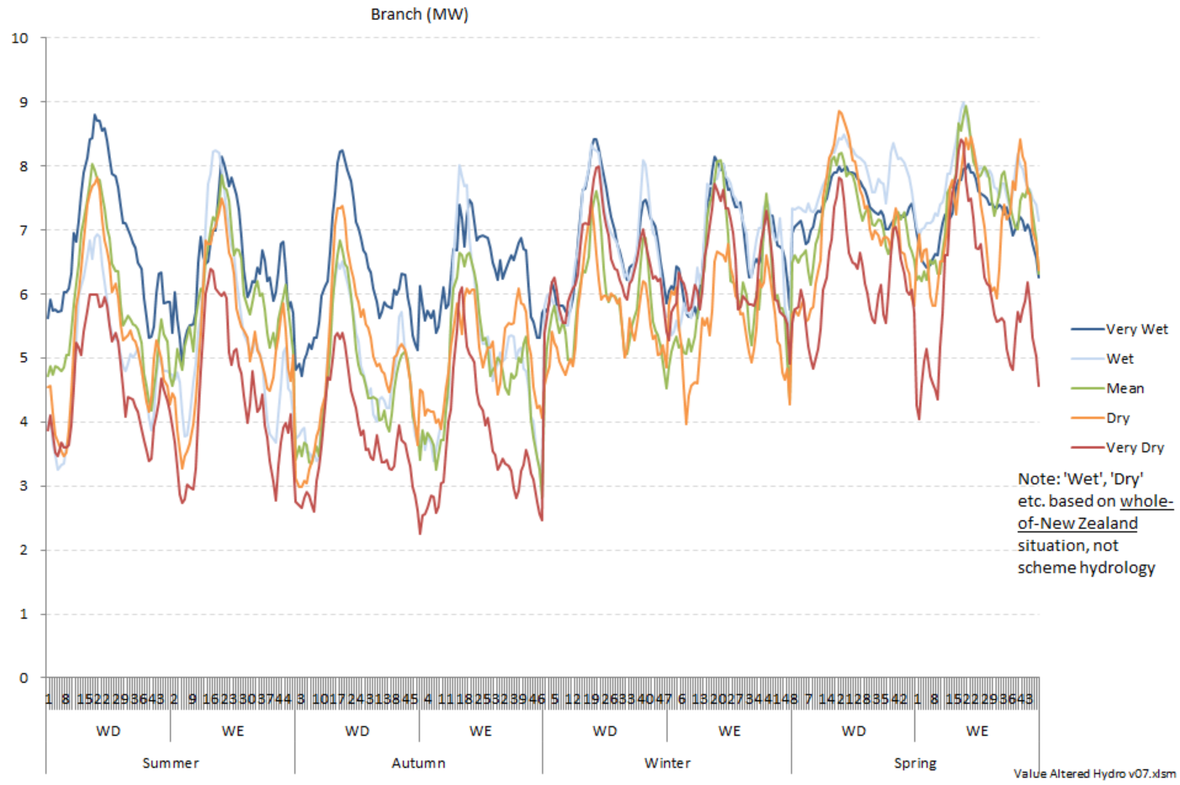
Figure 61: Schematic of Branch hydro scheme



As the following figure illustrates, there is some reasonable ability to sculpt Branch generation on a within-day basis, but there is no material ability to sculpt generation on a seasonal basis. Given the seasonal pattern of inflows experience by the scheme, it appears that its within-year pattern of generation is slightly anti-correlated with that of demand. i.e. Summer generation appears higher than Winter generation.

The pattern of Dry and Wet periods for Branch also appear to be correlated with the pattern of dry and wet periods for New Zealand overall.

Figure 62: Historical average pattern of Branch generation for the period 1989 to 2012



Trustpower modelling of impact of altered minimum flows

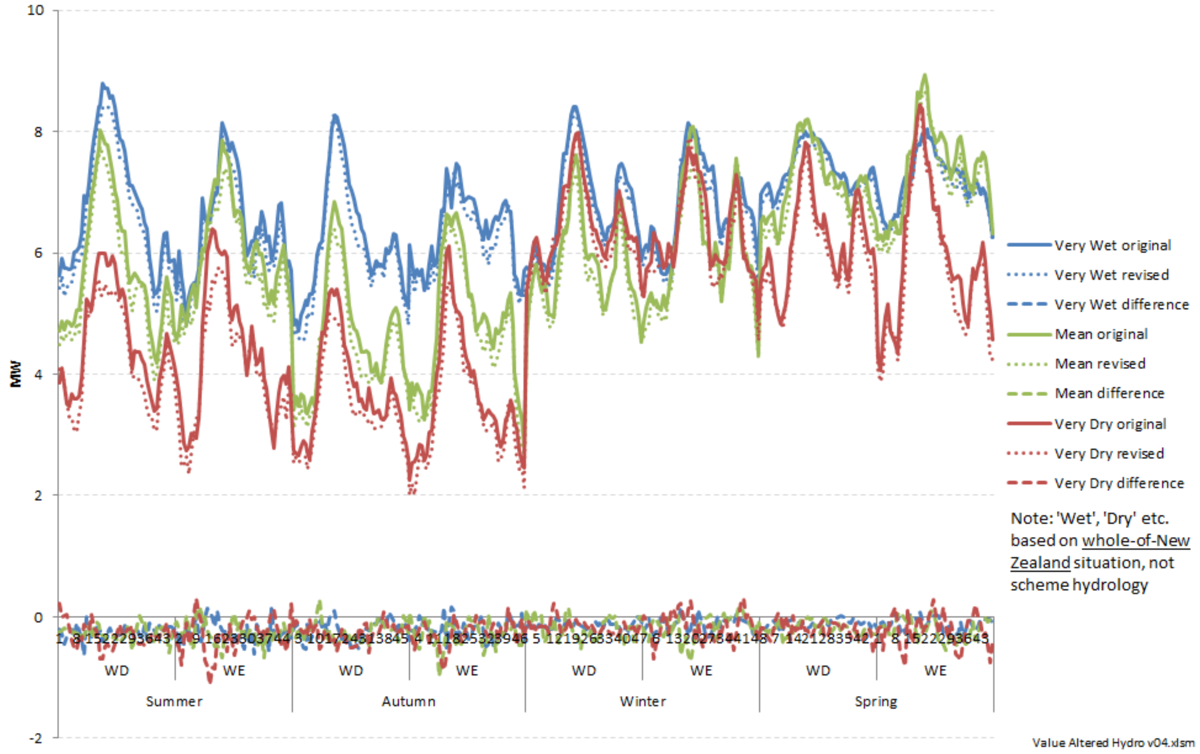
The following table indicates the scale of generation loss associated with the different scenarios.

Scenario	Loss of generation
5% increase on existing	0.43%
10% increase on existing	0.87%
40% increase on existing	3.48%
5% of MALF	0.00%
40% of MALF	1.92%
80% of MALF	12.71%

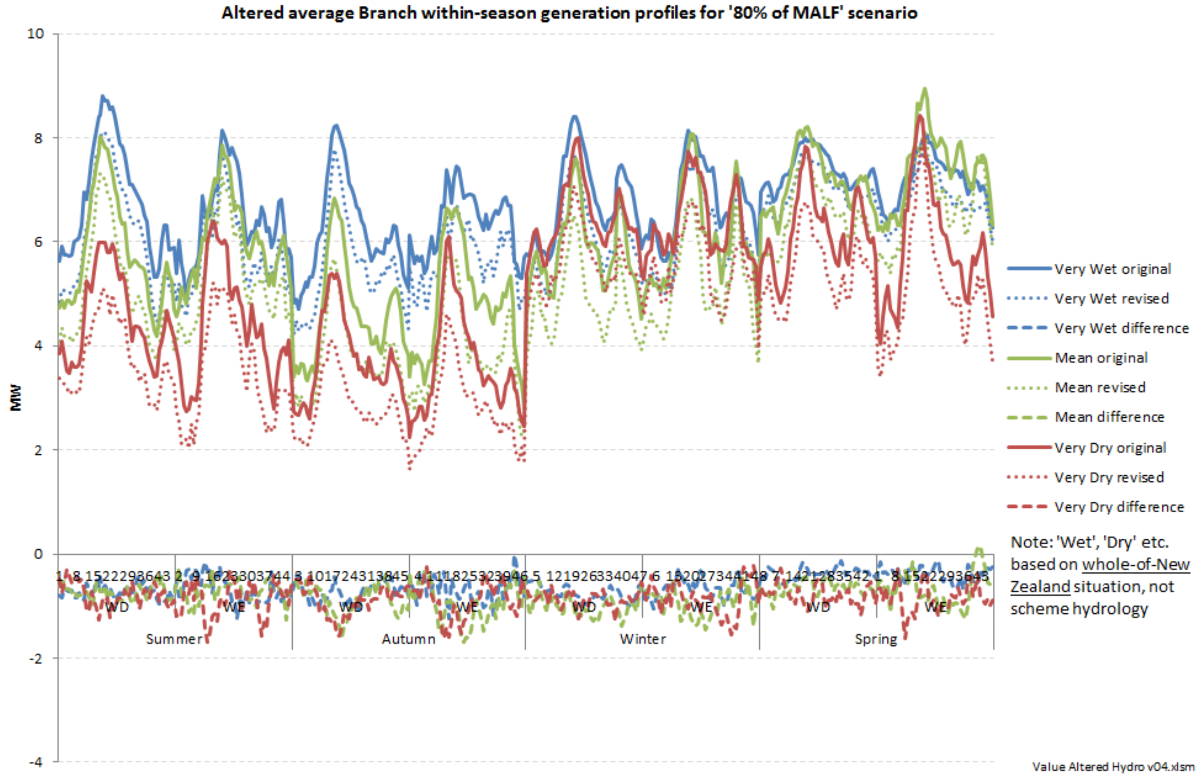
The following graphs illustrate the likely change in generating patterns for the Branch scheme arising from the altered minimum flow regimes.

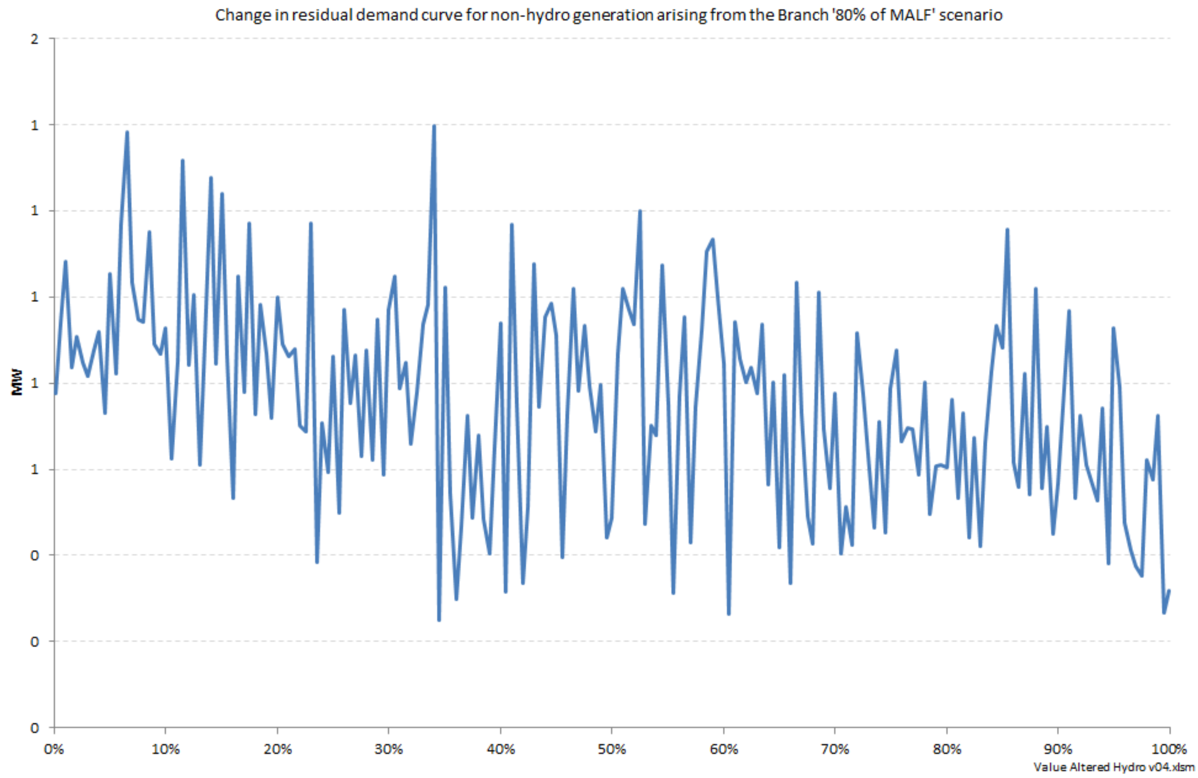
They indicate that the majority of such lost generation will need to be met by an increase in non-hydro baseload generation, with a relatively small increase in non-hydro peaking generation.

Altered average Branch within-season generation profiles for '40% increase on existing' scenario



Altered average Branch within-season generation profiles for '80% of MALF' scenario





Huntly Power Station

Huntly power station comprises 6 generating units – 4 x 250 MW coal/gas fired stem units (one of which has recently been put into long term storage) known as Huntly (1-4), a 400 MW combined cycle gas turbine (CCGT) unit known as Huntly 5 and a 48 MW open cycle gas turbine (OCGT) unit known as Huntly 6. The station has consents allowing up to 40 cumecs[76] to be drawn from the river. This is largely for cooling purposes for the Huntly (1-4) units with very small amounts used on site for operational requirements (approximately 98% is returned to the river). A mechanical draft cooling tower (installed in 2006 costing around $30m) cools water from one of the 250 MW generating units before it is discharged into the Waikato River.

Relatively complex consent requirements, among other things, limit the fully mixed temperature downstream of the station to no more than an increase of 2°C and no more than 25°C absolute. Historically these requirements have constrained the station's capacity to generate to varying degrees depending on prevailing ambient temperature, cloud cover and river flows particularly in the December to April period (i.e. the warmest months of the year).

Historically, river heating limits have constrained the operation of the Huntly (1-4) power station during some periods during the summer months – i.e. when the river temperature is at its highest.

It is understood that the cooling arrangements for the CCGT and OCGT do not rely on substantial water extraction from the river, and thus are not materially affected by river heating constraints.

Looking forward a number of factors are likely to reduce the incidence of periods when river heating constraints are likely to bind on Huntly (1-4) – even with status quo minimum flows:

- One Huntly unit has been put into storage, and another has had a cooling tower installed in 2006. This only leaves two Huntly units requiring river water for cooling.

76 With all 4 steam units in service (1 unit was recently placed in long term storage)

- Genesis Energy's stated intention to put another unit into storage in 2015.

Further, to the extent that minimum flows are *increased* on the Waikato, this should additionally reduce the amount of time Huntly's operation is constrained due to river heating constraints.

That said, if the Waikato minimum flows are unchanged, but increased minimum flows in the TPS diversions reduce the amount of water flowing into the Waikato, it is likely the case that the river will be operated at close to minimum levels for a greater proportion of the time, thereby increasing the time when such low levels may constrain the operation of thermal plant.

However, analysis set out in evidence[77] provided for the 2010 RMA hearing relating to the Waikato river suggests that the magnitude of any such impact is likely to be relatively small. This evidence considered the likely impact of increased abstraction of water upstream of the Huntly power station. Scenarios of increased abstraction of 1, 5 and 8 cumecs were considered. The effect of such abstraction could be considered equivalent to lowering the volume of the river flows at Huntly power station by such amounts.

The analysis considered the impact of such increased abstraction levels for 11 historical years (2000 to 2010) in terms of loss of generation from Huntly (1-4).

For the scenario of abstraction of 8 cumecs (equivalent to reducing the minimum flow in the river at Huntly by 5.4%) the average annual impact across the 11 years was a loss of 27 GWh.

This is considered likely to be a similar order of magnitude to the impact of the loss of the TPS diversions because:

- The river levels modelled in this RMA evidence were lower than that which would occur in a TPS diversions scenario. Instead, the TPS diversions scenario would result in minimum flows which were 5.4% higher than the 8 cumecs abstraction scenario, but for longer periods.
- The abstraction analysis in the RMA evidence considered *historical* Huntly (1-4) operation which, as set out above, is likely to be higher than *future* Huntly (1-4) operation – i.e. due to 1 unit being put into long-term storage, and the changing role of Huntly (1-4) towards increasingly low capacity factor operations.

Because any altered Huntly generation outcomes will almost always occur during the summer months, it is considered that any such loss of Huntly (1-4) generation will not have any implications in terms of increased need for system capacity. In other words, the system cost implications will be limited to the difference in the variable costs of operation between Huntly (1-4) and the replacement thermal plant that would be required to run instead. i.e. any increase in fuel, CO_2 and other variable operating costs for the replacement plant (most likely a CCGT or potentially an OCGT) would be offset by the avoided fuel, CO_2 and other variable operating costs of Huntly (1-4).

If this difference in the variable cost of generation between Huntly (1-4) and the replacement thermal generation were \$20/MWh, and if the average annual loss of Huntly (1-4) generation due to TPS diversions were equivalent to that calculated as part of the analysis on increased abstractions – i.e. 27 GWh/y – then the average annual cost of such lost Huntly (1-4) generation would be

27 GWh/yr * \$20/MWh = \$0.54m/yr

[77] Statement of evidence of Robert John Keller on behalf of Genesis Energy, in the matter of an appeal under clause 14(1) of Schedule 1 to the Resource Management Act 1991 in repsect of Variation 6 to the proposed Waikato Regional Plan, 15 October 2010.