Summary of comments on costs and benefits

Credentials of John Culy

I am an energy and utility economist with more than 40 years' experience in both the public and private sectors.

I advise the electricity industry in New Zealand, with particular expertise in hydro-thermal power system modelling, system security analysis, electricity and transmission spot pricing, and the economics of energy companies.

For more than 10 years I was Senior Economist at the New Zealand Institute of Economic Research. In 1998 I joined Morrison & Co, the management arm of utility investor Infratil. There I advised on energy asset valuation and due diligence, risk management, competition analysis, regulatory reform, energy market design in the New Zealand and Australian markets, and economic and market issues associated with renewable energy developments internationally.

I now practise as an independent consultant and am also an Associate of Concept Consulting, advising government agencies and private sector clients on a range of energy market and policy issues.

I hold a Bachelor of Science in Physics and Mathematics, and a Diploma in Statistics and Operations Research.

In recent years I have provided advice:

- to the Interim Climate Change Committee on issues relating to achieving 100% renewable electricity in New Zealand by 2035
- to the Climate Change Commission on economy-wide emissions modelling
- on the NZ Battery Project, including modelling of the potential benefits of large-scale pumped hydro and other forms of long-duration storage in New Zealand
- to MBIE on offshore wind economics and, with Concept Consulting, on New Zealand electricity price scenarios
- to the Market Development Advisory Group, with Concept Consulting, on price discovery under a 100% renewable electricity system in New Zealand, and on electricity price scenarios

I confirm that I have read the Code of Conduct for Expert Witnesses contained in the Environment Court Consolidated Practice Note 2023, and I agree to comply with it.

Introduction

In this section, I comment on the costs and benefits analysis presented in Meridian's application.

First, I explain Meridian's scenario choice and set out my own approach to scenario selection. In particular, I explain why I used bounding scenarios to assess the maximum plausible range of costs and benefits, rather than attempting to model the status quo and the counterfactual exactly.

Secondly, I summarise my assessment of the ongoing operational benefits of easing access to contingent storage. In broad terms, these benefits arise from less conservative lake management and lower expected system operating costs.

Thirdly, I explain why Meridian's focus on spot price effects and load-weighted spot costs does not, in my view, provide an appropriate basis for a national cost-benefit assessment. In my opinion, the more relevant measure is the change in overall system costs and, more broadly, total surplus.

Finally, I comment on the potential costs of removing the current limitations on access to contingent storage. These potential costs arise mainly in low-probability, high-impact contingency events. While I have not attempted to quantify their full national cost, I use an illustrative double-contingency example to demonstrate the possible scale of the issue.

Overall, my assessment is that easing access to contingent storage is likely to provide an ongoing operational benefit. However, that benefit is materially smaller than Meridian's reported load-weighted spot cost effects would imply, and it must be considered alongside potentially significant costs under adverse contingency scenarios.

Meridian's scenario choice

Meridian's application includes an Economic Costs and Benefits Report (Appendix A[1])), drawing on modelling set out in Appendix B.

Appendix B compares outcomes under two scenarios:

- **Meridian restricted scenario:** reflects a risk-averse approach to low lake levels, in case external enabling rules do not align with Meridian's own forecasts.
- **Meridian eased scenario:** reflects Meridian's view of prudent commercial operation using the full lake range within engineering limits, without restrictions associated with the Alert Contingent Storage Release (ACSR) and Official Conservation Campaign (OCC) triggers[2].

In practice, the **Meridian restricted** scenario models a case in which contingent storage is hardly used at all (see Appendix B, Figure 2), whereas the **Meridian eased** scenario reflects operation with effectively unrestricted access to contingent storage.

The modelling covers 2026 to 2029, with key quantitative results summarised in Appendix B, Figure 6.

[1] Appendix-A-Pukaki-Contingent-Storage-Project-Economic-Benefits-Report-3-October-Final-Version.pdf.

[2] These triggers are based on the 4% and 10% risk curves and some buffers.

My approach to scenario choice

To explore the trade-offs involved in the use of contingent storage, Transpower commissioned me to undertake independent modelling.

As in Meridian's Appendix B[3], I assessed outcomes under two bounding scenarios designed to estimate the maximum plausible range of costs and benefits.

- **Restricted scenario:** a bounding case in which contingent storage is not used at all under historical inflow sequences.
  - This was not intended to represent the status quo exactly, because the status quo allows for the use of most contingent storage when the ACSR trigger is met and additional contingent storage when OCC trigger is met. I did not attempt to model the status quo exactly, because that would have required modelling the evolving forecasts that determine those triggers[4]. Instead, to establish an upper bound on the potential benefit of easing access, I adjusted the Pukaki operating guidelines so that storage does not enter the contingent zone at any point over the historical inflow sequences.
- **Unrestricted scenario:** reflects the outcome sought by the application, with Meridian having access to contingent storage without trigger-based restrictions.
  - It is not possible to predict exactly how Meridian would operate under its own commercial incentives, because this would depend on contract positions, exposures, and risk preferences. Accordingly, I modelled unrestricted use by adjusting the Pukaki operating guidelines so that simulated storage under historical inflows could fall to around 200 GWh, at which point operational constraints would materially limit MW output from the Waitaki scheme. It is reasonable to assume that Meridian would have strong commercial incentives not to operate below that level.

These scenarios do not correspond exactly to the factual status quo and the counterfactual without restrictions. Rather, they are stylised bounding cases used to assess the maximum plausible difference between restricted and unrestricted access.

They therefore provide bounds around the maximum potential difference in outcomes.

Layton[5], in his review of my work, appeared to interpret my restricted case as if it were intended to represent the status quo. That was not its purpose. It was a modelling

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[3] Appendix-B-Pukaki-Lake-Management_Memo_Sep-2025.pdf.

[4] Another factor was the uncertainty concerning the size of buffers used in the determination as these were likely to be changed because of the ongoing SOSFIP review. As it turned out the buffers were increased in the final EA approved SOSFIP, see https://www.ea.govt.nz/documents/2711/SOSFIP.pdf

[5] Brent Layton - Memo on Transpower's December Paper on Security of Supply Issues - 15 Dec 2025_c - Final.pdf, page 2 Key findings para 1.

device used to identify the upper bound of the potential benefit from allowing unrestricted access, relative to the status quo.

In substance, my approach is very similar to Meridian's Appendix B approach, in which the status quo is also represented by a case where contingent storage is hardly used at all.

The true difference between the status quo and the counterfactual will lie somewhere between:

- **zero**, if the ACSR and OCC triggers effectively align with Meridian's own commercial operation absent restrictions; and
- **the maximum bound estimated by the modelling**, if Meridian's unrestricted commercial operation would in practice make substantially greater use of the contingent zone than is permitted under the current triggers.

Key economic trade[6]-offs

At a high level, the application involves a trade-off between:

- the ongoing **operational benefits** of operating the lakes without restriction, compared with the current trigger-based restrictions; and
- the **potential costs** of allowing unrestricted use in circumstances where Meridian's commercial incentives may differ from the broader national interest reflected in the existing consent conditions, which provide public assurance that contingent storage is held in reserve and used only when security risks breach critical levels, taking into account inflows, plant outages, and fuel supply contingencies.

The **ongoing operational benefits** can be assessed using simulation methods based on historical inflows, wind and solar variability, and technical assumptions such as lake operating guidelines, thermal capacity, fuel costs, and demand response costs, although quantification remains difficult[7]. My quantitative analysis focused on that aspect.

The **potential costs of unrestricted access** arise mainly in low-probability, high-impact situations where commercial risk preferences may differ from the national perspective embodied in the system operator's implementation of the Electricity Authority's Security of Supply Forecasting and Information Policy. These costs are particularly relevant under multiple contingencies, such as major thermal plant outages or fuel supply shortages, because such events may lead to prolonged supply restrictions and broader economic and reputational impacts for the country.

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[6] There are other trade-offs as well, such as environmental and regional, but my focus is on the economics.

[7] Note that this history provides a benchmark for future variations in inflows and wind/solar but there is still considerable uncertainty relating to the impacts of climate change.

Assessment of the appropriate level of national risk tolerance for such events is a matter for government and the Electricity Authority. It was not part of my brief to determine that policy judgement.

Accordingly, my analysis was limited to demonstrating the potential scale and impact of a single illustrative **double contingency**: low inflows combined with a major long-term plant outage of the kind experienced in 2023.

In his review, Layton[8] appeared to favour applying a probability weighting to the results of that illustrative scenario. I did not adopt that approach, because any meaningful weighting would be highly dependent on explicit quantitative judgements about:

- the probabilities of, and correlations between, the various multiple contingencies that could arise over the next few years, particularly during the period in which gas fields are depleting and the system continues to rely on potentially vulnerable coal and gas supply chains, storage and stockpiling supply chains, and ageing thermal plant;
- the longer-term flow-on effects on New Zealand's economy and reputation if such events resulted in extended periods of electricity rationing over days, weeks, or months; and
- the level of risk the country is willing to accept.

Those issues were beyond the scope of my work.

My assessment of ongoing benefits

The details of my assessment of ongoing benefits are given in my summary report[9].

Ongoing benefits arise primarily from operating the lakes less conservatively to avoid breaching the contingent zone. This tends to:

- shift releases from hydro storage earlier;
- run thermal plant and lower-cost demand response later and less aggressively;
- hold lake levels lower on average;
- reduce spill risk, and spill in some periods; and
- lower fuel and variable operating costs.

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[8] [Layton Dec25] Brent Layton - Memo on Transpower's December Paper on Security of Supply Issues - 15 Dec 2025_c - Final.pdf, page 2 Key findings para 1.

[9] See [**JC2 Sep25**], "Contingent_storage_Final_Summary_Report_20Sep25"; https://static.transpower.co.nz/public/bulk-upload/documents/Contingent_storage_Final_Summary_Report_20Sep25_V2.pdf?VersionId=0N4nD5Vcu56YDa6ktn0yRA7SS3KDn4G7. A similar methodology was used for the NZ Battery Project, see culy-november-2022-estimating-the-gross-benefits-of-nz-battery-options.pdf, and culy-november-2022-nz-battery-grossbenefit-appendix.pdf.

I agree with Sapere and Brent Layton that removing restrictions on access provides an ongoing benefit, and I agree that there are modelling issues that make quantification difficult.

From a national cost or public welfare perspective, the relevant measure is the reduction in system costs, including:

- fuel costs, including the cost of diverting gas from methanol production;
- short-run variable operating costs;
- carbon costs; and
- the cost of market demand response.

Simulating the system over multiple historical inflow sequences provides a reasonable basis for bounding those costs[10].

My modelling estimates a maximum benefit range of **$38–$43** million[11] per year over 2026–2028, that is, of the order of **$40** million per year[12].

The true benefit relative to the current ACSR and OCC triggers will be lower, depending on Meridian's commercial operation and risk preferences relative to the system operator's trigger-based assessments. My assessment is that the true benefit is more likely to be around 50% of the maximum, or around $**20** million per year[13].

Issues with Meridian's focus on spot prices and load-weighted spot costs

Meridian does not report system cost differences directly. Instead, it focuses on:

- wholesale purchases from the Reconciliation Manager rather than what normal retail customers pay;
- modelled impacts on wholesale spot prices; and

[10] My analysis employs a sequential wrap-around simulation approach, whereby a full set of historical inflows are simulated for a target year. This simulates lake levels for a set of inflows over a single year where the starting lake levels are determined from the ending level for the previous flow year. This technique ensures that the impact of sequential runs of inflows is accounted for and that issues relating to the valuation of water in storage at the start and end of the target year are avoided. This is important when we are assessing the relatively small changes in system costs between the scenarios.
[11] This range is across the 2 and 3 Rankine scenarios.
[12] This estimate of maximum benefit is of the order of 5% of total system costs. Total system costs can vary significantly depending on fuel level costs (e.g. gas prices have at least a 30% uncertainty). However we are looking at the difference in cost due to restrictions on contingent storage, so a 30% fuel cost change would translate to around a ± $12m error in the $40m/yr. Given this there is likely to be a significant benefit > 0, but the magnitude is uncertain relative to $40m/y.
[13] See [**JC2 Sep25**], slide 15 top right chart which shows the benefit falls from saving a maximum of $38m/year down towards $19m/yr in alternative less restrictive scenarios, such as the status quo.

- based on those modelled impacts, changes in wholesale electricity load-weighted spot cost.

There are several reasons why this focus is problematic.

Spot prices

- Meridian estimates that unrestricted access would lower spot prices by **$10/MWh**.
- In a hydro-dominated market, prices above thermal guidelines are not well defined and depend heavily on offer behaviour.
- Any price reductions from deferring high-cost thermal operation may be offset by lower prices in periods when lakes are held higher and spill risks increase.
- Multiple contingency events (fuel supply disruption and/or thermal outages) could produce substantially higher prices[14], but these are difficult to quantify reliably.

My estimates[15] suggest that, if offsetting negative price impacts are ignored, the maximum reduction is around **$5–$7/MWh**. Once offsetting impacts are included, this becomes around a **$2–$3/MWh** increase. Both estimates are within typical uncertainty margins for spot price impact estimates of more than ±10%, or about ±$15/MWh. It is therefore not possible to conclude with confidence that unrestricted access would reduce spot prices.

Load-weighted spot costs

Meridian estimates a change in load-weighted spot cost of about **$437** million per year, based on roughly 43 TWh of demand and a $10/MWh reduction in spot prices.

This value largely represents a wealth transfer from spot generators to spot customers under an inelastic demand framing, rather than a national net benefit.

Under standard welfare accounting:

- a reduction in spot prices increases **consumer surplus** for spot-exposed customers;
- the same reduction decreases **producer surplus** for spot-exposed generators; and
- these two effects largely offset one another, because supply equals demand, leaving the **net national benefit** equal to the change in **system costs**.

Accordingly, the relevant metric for **national cost-benefit analysis** is the change in **system costs**, not gross changes in load-weighted spot payments.

[14] For example, by avoiding scarcity prices of $6,500 to $50,000/MWh.
[15] See slide 18 in JC2 Sep25 which shows the potential range of price impacts accounting for both positive and negative impacts.

Meridian has not reported total surplus changes or system cost benefits, but these are likely to be an order of magnitude lower than the reported transfer.

Contracting further complicates interpretation. Contracts can materially change who is effectively exposed to spot prices. As Meridian notes, generators can be effectively "spot customers" (and vice versa) depending on contract positions and the timing of exposures.

Tracking net impacts on traditional customers and generators would require detailed knowledge of contract terms and positions. Meridian's analysis did not attempt to determine how their spot price impacts would flow onto retail customers and other non-spot exposed consumers. Fortunately, this is not required for a national cost-benefit analysis, because most spot price impacts are transfers and the total surplus change is captured by changes in system costs.

In summary:

- spot price impacts depend on offer behaviour, which is difficult to predict;
- the estimated spot price impacts are within the likely estimation error;
- even where spot price effects arise, the impact on customer and generator surplus is complicated once contracts are taken into account; and
- the relevant measure for national cost-benefit analysis is the change in total producer and consumer surplus, which is most reliably assessed through changes in system costs.

Assessment of potential costs of removing current limitations

As explained earlier, I did not attempt to quantify the full costs of removing the existing limitations on Meridian's use of contingent storage.

Such quantification would require assessment of public risk tolerance and resilience values, as well as multiple-contingency outcomes beyond simple weather variation. It would also require judgement about possible longer-term economic and reputational impacts of supply restrictions.

However, I illustrated the scope of the issue using an example double contingency: low inflows combined with a major long-term plant outage, of the kind experienced in 2023.

This example is illustrative only. Many other double-contingency events could plausibly occur over the next few years, including:

- reduced gas availability for electricity generation (for example, failure to negotiate diversion from industrial gas uses such as methanol production, supply outages, or depletion);
- local gas storage constraints;
- long-duration outages in ageing Huntly Rankine units;

- insufficient coal stockpiles to sustain winter operation; and
- broader fuel supply chain vulnerabilities (including due to geopolitical issues).

These fuel and backup capacity risks are particularly significant over the next three years, until more renewable generation is built and/or additional gas storage or infrastructure comes online.

Key observations from the illustrative modelling

1. The potential impacts[16] of unrestricted use of contingent storage can be large, with shortage costs of the order of **$440–$740**[17] million in 2026 and spot price impacts of the order of **$140/MWh**[18].
2. These shortage costs include the estimated short-run variable costs of compensating customers for demand reductions. They do not include any indirect longer-term flow-on impacts on the wider economy.
3. These impacts are most significant over the next three years, and then decline as additional renewable generation is built and system resilience improves.

[16] Note that I have measured the potential impact as the difference between the fully restricted and unrestricted outcomes, consistent with the "bookend" assessment of ongoing system costs. See JC2 Sep25 slide 17.
[17] For 2 and 3 Rankine units in 2026.
[18] Averaged over whole year in 2026 with 3 Rankine units.