Ministerial Briefing
LNG and the impacts on the electricity system

Date	10/04/2026	**Priority**	Medium
Security classification	In Confidence	**Electricity Authority reference number**	BR-26-0011

Action sought		
	Action	**Deadline**
Hon Simeon Brown Minister for Energy	**Note** the contents of this briefing	
Appendices included	None	

Contact for telephone discussion if required			
Name	**Position**	**Telephone**	**1st Contact**
Hayden Glass	GM, Wholesale and Supply	S9(2)(a)	✓
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Drafter	Doug Watt	**Position**	Manager, Market Intelligence

The following departments/agencies have been consulted

Minister's office to complete

☐ Approved ☐ Declined

☐ Noted ☐ Needs change

☐ Seen ☐ Overtaken by events

☐ See Minister's notes ☐ Withdrawn

Comments

Briefing Purpose

This paper responds to your request for a briefing on the impacts of liquified natural gas (LNG) on the electricity system.

Summary

- We think an LNG import terminal could improve electricity system reliability and reduce wholesale electricity prices in times of high demand.
- It is harder to say whether an LNG import terminal is the best available solution. We don't expect wholesale electricity prices to remain elevated after the next few years. More gas should come to market once Maui and Methanex shut down next year. Coal is a cheaper fuel than LNG. And enabling LNG imports will increase domestic gas prices.
- We expect that, regardless of the original incidence of a levy, consumers will end up paying most of the levy in practice. We don't think it is practical to observe whether passthrough of the levy to retail prices is or is not happening, given the relatively small scale of the levy costs.
- We expect any reduction in fuel costs from LNG would be reflected in wholesale energy prices. We do not think the impact of LNG will be observable in market prices on its own, given how volatile wholesale prices are.
- Firms are investing in generation and in contingent arrangements that shrink the dry-year risk. But our system relies on private investment incentives and it is hard to make investment in dry-year risk reduction projects, like the LNG import terminal, stack up commercially.

Recommended action

Hon Simeon Brown, Minister for Energy

It is recommended that you:

1. Note the contents of this briefing	**Noted**

Hayden Glass
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10 April 2026

Hon Simeon Brown
Minister for Energy

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1. Background

1.1 This briefing responds to your request for some advice on the impacts of LNG on the electricity system.

2. Is an LNG import terminal needed for electricity generation

2.1 The Electricity Authority's goal is reliable electricity at the lowest cost for consumers. Our definition of "need" therefore is whether an LNG import terminal would improve electricity system reliability or reduce total electricity system costs.

2.2 In short, we think it could improve reliability and reduce wholesale electricity prices, but whether it is the best solution on those terms is more difficult to say.

2.3 More fuel combined with the equipment to convert it into electricity improves electricity system reliability, so in that sense an LNG import facility is good for reliability. In particular:

(a) LNG has the virtue of being available internationally in essentially unlimited quantities (in normal times).

(b) It is no less available, even in abnormal times, than alternative imported fuels, like diesel.

(c) We have existing gas generation plant that can readily burn imported LNG. So no new generation plant needs to be built to use LNG to generate more electricity.

2.4 More fuel could also put downward pressure on wholesale electricity prices (depending on the cost of that fuel and, in the case of LNG, considering the cost of the terminal itself):

(a) Our modelling shows that LNG at $25/GJ could lower wholesale prices provided there is spare thermal generation capacity available. LNG at $25/GJ translates to around ~$200/MWh for energy from Huntly Unit 5 (our most efficient thermal generation unit).

(b) As an example from 2024, if all uncleared Huntly 5 energy (energy offered above the marginal spot price in any half hour) was offered at $200/MWh, the average national marginal price would have reduced by $22/MWh. This is not to say LNG will reduce prices by $22/MWh in every year, but it does indicate its significant possible impact during a year that had periods of very high wholesale prices.

(c) This is not to say that LNG will cap electricity prices entirely, ie, that electricity prices won't ever go above $200/MWh. This is because there isn't unlimited capacity to generate electricity from LNG. The effect of LNG is to bring a large quantity of supply into the market at $200/MWh. This could take the top off wholesale prices to a material extent, but in periods of limited fuel and high demand, prices above the cost of LNG are likely as hydro generators seek not to run to conserve water for the future.

(d) Hedge prices for future September quarters (shown in the graph below), are volatile and it is hard to see a clear impact from the LNG announcement. But there is some support for the existence of this price effect in market announcements. In particular, we have seen Channel Infrastructure put on hold their investigations into building a new diesel peaker at Marsden Point. And we expect that, if LNG proceeds, Contact will also be looking at options for its Whirinaki diesel plant in Hawkes Bay. There is no prospect of these plants covering their fuel costs when diesel-fired energy even in normal times costs around twice what LNG does.

2.5 Whether an LNG import terminal is the best available solution is harder to say:

(a) We aren't sure that wholesale prices will be elevated past the next few years. We are discussing with Concept Consulting, who did the numbers for MBIE, how the $30 to $50

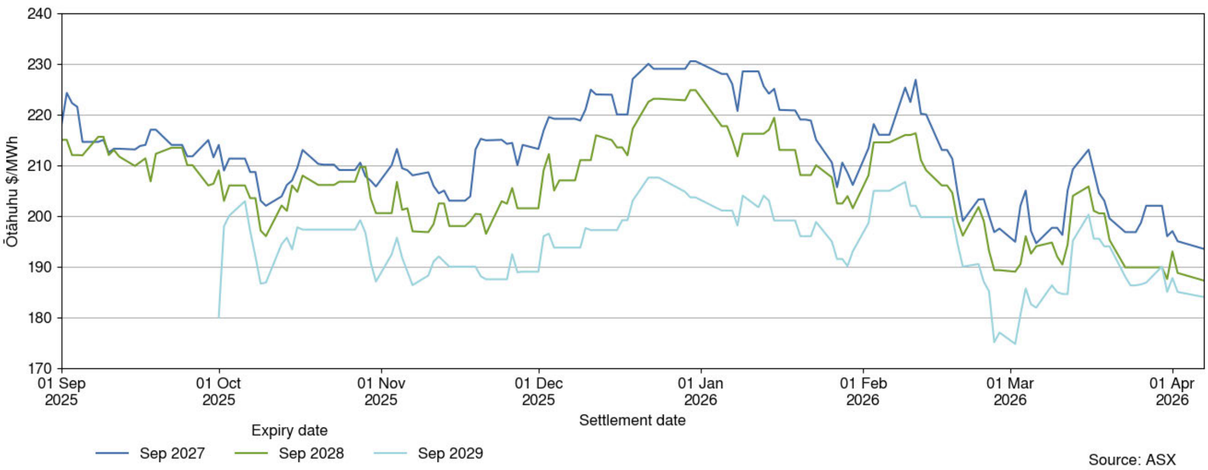
/ MWh "dry year premium" figure was derived. Our long-term hedge data and generation pipeline data suggests that forward prices converge to the cost of new generation in 2030 due to anticipated generation build (this is already true of summer prices; by 2030 it is expected to be true on average across the year). All the extra cheap generation should force hydro generators to run less, increasing average storage and reducing our vulnerability to a dry season. In short, whatever the premium size or cause, it does not seem like a problem beyond the next few years.

(b) Very long-term modelling suggests it might re-emerge in the future. However, if it is going to re-emerge, it would be cheaper to build more coal generation than to build an LNG Import facility. This is because, in the long-run, fuel costs dominate plant costs, we may have no appreciable domestic gas, and LNG is more expensive than coal. MBIE's analysis is that it would take longer to build new coal generation than to build an LNG import facility.

(c) The anticipated shutdown of Maui and Methanex next year will more than likely mean that there is more gas available (because the gas that Methanex sources from fields other than Maui will become available to the market).

(d) LNG does have a helpful insurance effect in the gas market, providing an option for gas users who can't switch even if domestic gas production continues to surprise on the downside. But customers could face high prices and limited availability as generators bid up the price of domestic gas. This would be particularly felt for those who were coming out of domestic gas contracts when gas was at a premium for electricity generation.

Figure 1: Ōtāhuhu September quarter future prices for 2027, 2028 and 2029



3. Is the proposed terminal the right size

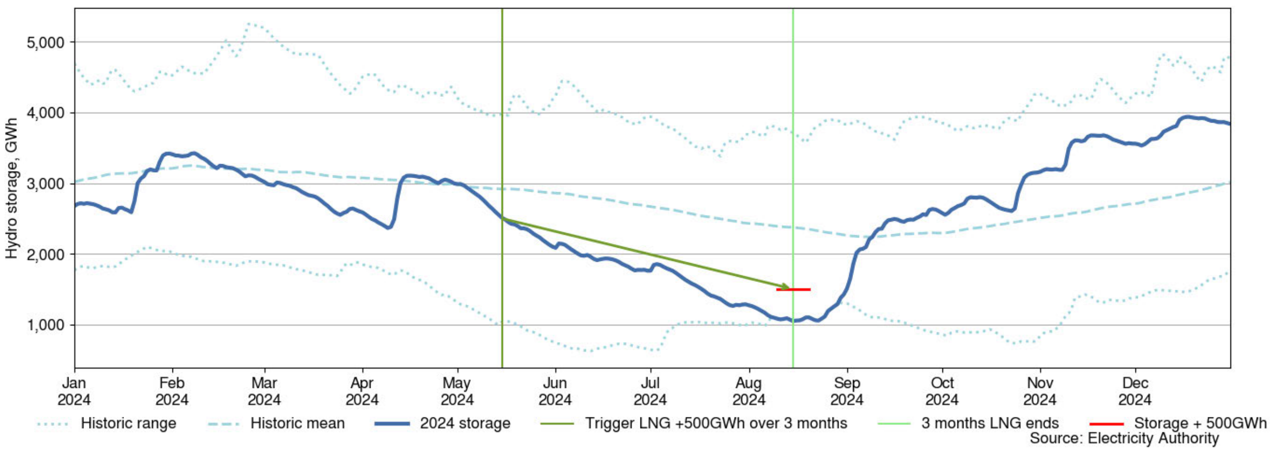
3.1 It would be important to ensure that imports were sufficient to fuel the generation plant we already have to convert LNG into electricity. Imports below that level would leave a gap. Imports above that level would be unlikely to be used.

3.2 Our view is that the amount of LNG that could be usefully used in the electricity system is at most around 6PJ (800GWh) in a year. This is around one and a half cargos from the most common class of LNG carrier. This number is determined by how much capacity we have to generate electricity from gas in three months. It is dependent on domestic gas production and on how generators contract for gas. Further, as little as 500GWh could make a material difference to the power system during a dry season.

3.3 In 2024, over the months of June, July and August, we estimate there was around 565GWh of spare gas generation capacity. This assumes the dual fuel Rankines at Huntly are running on coal, and all available gas generators are running at a realistic level of 70 per cent capacity. An upper bound is probably 85 per cent capacity or around 846GWh. Running at 100 per cent there is another 282GWh of capacity available to burn gas, but that does not allow for operational issues like unplanned outages, which are more likely with the old thermal kit especially when running at very high output.

3.4 Figure 2 shows how an additional 500GWh added to the power system over three months would have affected hydro storage in 2024. This assumes that the energy from LNG displaces hydro—at the time the costliest fuel – and that it arrives at the optimal time. On these assumptions, storage would have fallen to a low point of 1,500GWh in winter instead of 1,000GWh. (By way of comparison, storage fell to 1,500GWh in 2025 without causing any disruption.)

Figure 2: Impact of adding 500GWh of energy on 2024 hydro storage levels



Source: Electricity Authority

4. How should a terminal be paid for and what about passthrough of the costs and benefits

Terminal costs

4.1 The costs of an LNG facility funded by an industry levy, regardless of its initial incidence, will ultimately be borne by a mix of consumers and producers. The mix depends on the relative elasticities of demand for electricity and its supply to changes in the price. Electricity demand is inelastic to price, in the short run especially, which means that more of the levy will ultimately be paid by consumers. We are not aware of any practical way to ensure the funds come only from generators.

4.2 Assuming media reports of initial capex of $1b are correct, the total costs (including financing over 20 years at six per cent) would be $1.7b, or $87m per year. This is around $15 - $37 per household per year for 20 years depending on how the cost is allocated (per ICP or per MWh), around 70 per cent of which is the cost of financing.

4.3 The average household electricity bill is about $2,800 a year, so this would be the equivalent of adding 0.5 - 1.3 per cent to the bill every year for 20 years. This is more than the ~0.5 per cent of bills that households currently pay for the costs of the Electricity Authority, System Operator and other system functions like market making, reconciliation and clearing. But it is still a small amount in terms of the total household bill. While the Authority is now starting to gather retail price data at the ICP level, we would not expect to be able to isolate what proportion of such a levy had been passed on to retail customers over time.

Wholesale price reductions

4.4 The wholesale electricity market is workably competitive. This means that any impact of LNG imports on fuel costs will be reflected in wholesale prices. Expected future reductions in costs will also be reflected in future prices.

4.5 But both spot and hedge prices are volatile, with many factors influencing prices every day. Even if the impact of LNG imports were quite large and the analysis was very sophisticated, it would still be very difficult to pick out.

4.6 The Electricity Authority monitors spot market offers very closely and checks that all offers match what we know about access to fuel and other operational issues. We also have access to information on all electricity hedges, which enables us to track wholesale electricity pricing over time in a reasonably intricate way.

5. Why hasn't the market solved this issue already

5.1 In our electricity market design, we rely on commercial incentives created primarily by expected future prices to incentivise generation investment. And dry-year risk projects are not readily bankable. Our framework for security of supply involves regular information provision, but there are few sticks in the regime, eg, no central party able to force, or to contract with, an entity to invest in backup generation plant. MBIE is developing advice for you at present on the dry-year regulatory framework that proposes some improvements to the regime. But it is difficult to materially alter private investment outcomes without significant costs and side effects.

5.2 The Expert Advisory Group that MBIE assembled to advise on the dry-year regulatory framework noted two main reasons why private investment in dry-year risk has a weak business case:

(a) There is significant revenue uncertainty, because by their nature dry years are not predictable. It is difficult to build a business case to invest in an asset with unpredictable cashflows. This trouble has been worsened by the retirement of thermal generation from year-round baseload generation, which means there are fewer trading periods to recover fixed costs, and by the decline of domestic gas production.

(b) The buy side and the sell side have misaligned timetables. Sellers are keen on stable cashflows over the life of their assets. Most electricity buyers do not in practice cover their demand for more than a few years ahead.

5.3 Nevertheless, commercial players have created and continue to create solutions to deal with dry years and other unpredictable fuel shortages:

(a) The primary solution is generation build, much of which is solar or wind and has no fuel cost. We expect that the energy from this new generation will continue to undercut hydro prices and effectively force hydro generators to store more water in their reservoirs. This will help insulate the power system from a dry season.

(b) As set out above, our data suggests that forward prices will converge to the cost of entrant generation by about 2030. Summer quarter prices are already below our estimate of the cost of new generation, and generation continues to be built with 352MW of wind, 851MW of solar, and 200MW of batteries expected by the end of 2028. Prioritising generation in fast-track type processes can only help. We observe it working for at least Contact Energy's Southland windfarm and Westpower's Waitaha hydro project.

(c) Hydro generators have for some time used swaptions to firm hydro in dry years. These have included deals with gas generators to sell a forward contract to the hydro generator if the swaption is called. This contract provides the return for the gas generator to run. We have seen swaptions sold by gas, coal and diesel generators.

(d) The Huntly Firming Options are a kind of swaption, with fuel risk transferred to the buyers. In terms of energy, the HFOs could contribute about 400GWh over three months if they were called.

(e) The Tiwai demand response agreements also help reduce the dry year problem. Tiwai demand response contributed about 330GWh in saved energy in 2024. These types of agreements are becoming more common: the new arc furnace at Glenbrook can be used for demand response. From the perspective of the EA — and with our specific mandate—we view demand response as a critical capacity and energy management tool as the power system becomes more renewable. However, we do acknowledge that these arrangements can be disruptive to the wider economy, even if the firms involved are being compensated for reducing their demand.

6. Next steps

6.1 This briefing is for your information.