Office of the Minister for Energy

Cabinet

Delivering Secure and Affordable Energy: Next Steps for LNG Facility Procurement

1 This paper reports on progress to procure liquefied natural gas (LNG) facility services and seeks Cabinet's direction on the way forward.

Relation to government priorities

2 A secure and affordable supply of energy is critical to economic stability and the Government's Going for Growth agenda.

Executive Summary

3 New Zealand's electricity system faces a critical and worsening risk from declining domestic gas production and the loss of flexibility that has historically helped manage dry-year conditions. These impacts are a direct consequence of the previous Labour Government's failure to invest in and secure reliable energy supply during its time in office. Gas supply is falling faster than expected, with the imminent closure of the Māui field and the exit of Methanex, permanently removing the only mechanism that prevented a full energy crisis in 2024 – the ability to redirect gas from industry to power generation at short notice. This safety valve is about to disappear, and nothing exists to replace it. In future dry years, this is likely to result in extreme and sustained electricity price spikes, forced shutdowns of New Zealand's largest industrial users, and – in a severe scenario – rolling blackouts. The economic damage would run to billions of dollars and, as history shows, would not reverse quickly once the crisis passed. Annex 1 illustrates how future dry years will have much more severe consequences for the New Zealand energy system and economy.

4 In December 2025, Cabinet agreed to procure liquefied natural gas (LNG) facility services as the preferred near-term option to strengthen energy security and manage dry year risk. LNG remains the lowest cost, most flexible and most timely way to provide firm fuel support from this decade. Without it, New Zealand has no credible dry-year solution before 2030. The procurement process is well underway, with two shortlisted proponents – Commercial Information – shortlisted following feasibility assessments. Both propose LNG solutions at Port Taranaki Commercial Information providing a credible path to delivery from 2028.

5 This paper revisits the way forward in light of worsening domestic gas supply and increased geopolitical uncertainty. While the conflict in the Middle East has increased short term volatility in global LNG markets, LNG forward prices for 2028–29 remain broadly consistent with earlier assumptions seen by Cabinet. Importantly, LNG commodity prices do not affect the cost of the import facility itself and the insurance value of having LNG available – already reflected in lower forward electricity prices reducing electricity costs to the economy by up to $800 million per annum[1] – remains unchanged.

[1] This represents the savings in electricity costs if the current $20/MWh reduction seen in forward contract prices flows through to all electricity used across the economy (~40TWh). This likely overstates total savings

6 The paper sets out the Government's intended approach to progressing LNG procurement. The paper also revisits funding arrangements for the LNG facility. My clear expectation is that responsibility for managing dry year risk rests with the electricity sector Confidential advice to Government

Background

7 In December 2025, Cabinet decided [CAB-25-MIN-0466 refers] to proceed with the procurement of an LNG import facility to enhance security of energy supply. The Minister for Energy was authorised to select the most promising accelerated proposals for further investigation. The Cabinet paper made clear that LNG being available for winter 2027 was not likely but that winter 2028 was a reasonable prospect. This would require signing a contract with a preferred LNG facility provider in mid-2026 and enabling legislation to be passed before the election.

8 Since Cabinet agreed in December to procure LNG facility services, a number of relevant developments have occurred. Most notably, domestic gas supplies have continued to decline and the outbreak of war in the Middle East has heightened global energy market risks. Critically, the domestic picture has deteriorated more quickly than anticipated: OMV has confirmed the Māui field will likely cease production this year, ahead of earlier projections. The loss of Māui, combined with the exit of Methanex, means the conditions that will define New Zealand's next dry year are materially worse than those Cabinet considered in December. In light of these developments, it is timely to take stock of progress and consider the way forward.

Do we need LNG and does the conflict in the Middle East change that?

New Zealand's dry-year risk is causing long-lasting economic damage

9 New Zealand's electricity system faces a structural challenge in managing dry-year risk. While the wholesale electricity market performs well in delivering energy in average conditions, it does not provide strong incentives for investment in firm electricity capacity that is used infrequently, delivers system-wide benefits and is primarily valuable during infrequent but high-impact dry conditions. This reflects a structural market failure identified by Frontier Economics in its recent review of the electricity market. The previous Labour Government's energy policy did not address this failure, leaving the system increasingly exposed as gas production declined and no replacement firm capacity was secured.

10 The electricity sector is delivering a strong pipeline of new renewable generation, demonstrating the market is responding to our Government's Electrify NZ agenda and growing demand. However, this investment has not translated into sufficient new firm-energy capacity to meet dry-year needs. A persistent risk premium of approximately $30–50/MWh has emerged in forward wholesale electricity prices.[2]

since some longer-term electricity contracts (e.g. the NZ Aluminium Smelter) have separately been agreed on very competitive terms.

[2] Because there is no clear back-up supply or plan for a dry year, the electricity market is pricing in the risk of shortages of fuel in future years. This is reflected in forward electricity contract prices, which flow through into electricity bills, putting pressure on the cost of living and slowing the economy.

While this premium is ultimately borne by households and businesses through higher electricity costs, it has not created a corresponding incentive for private investment in firm capacity.[3]

11 Energy scarcity is transmitted rapidly into the wider economy through higher prices, production shutdowns, and lost investment. Recent analysis indicates that sustained periods of high energy prices linked to fuel scarcity since 2017 reduced GDP by an estimated $5.2 billion (1.25 per cent) in 2025, lowered real wages and household spending, and weakened the trade balance. These impacts are a direct consequence of the previous Labour Government's failure to invest in and secure reliable energy supply during its time in office. Critically, the economic consequences of energy undersupply do not dissipate once prices fall or rainfall recovers. Evidence shows that even short-lived periods of energy scarcity can have long-lasting effects, including permanent firm closures, delayed or cancelled investment, and persistent employment impacts, with recovery taking up to decades. The next dry year, arriving into a system with no circuit breaker, would be materially worse than anything experienced between 2017 and 2025 – meaning the economic damage, if unaddressed, would exceed the $5.2 billion already inflicted in 2025 alone.

12 The experience of 2024 illustrates the impacts of the dry-year risk. Even in what was only a moderate dry year, gas supply constraints meant gas-fired generation could not run fully, coal generation operated at maximum and spot electricity prices exceeded $800/MWh. The New Zealand Aluminium Smelter turned production down under their demand response deal and some firms closed permanently. This is demand destruction. The system was ultimately stabilised when Methanex curtailed production and released gas to electricity generation, acting as an effective circuit breaker. That circuit breaker will not exist in the next dry year, as Methanex is exiting and the Māui field is closing. There is no equivalent user who can release comparable volumes of gas at short notice, and New Zealand has very little gas storage. In 2024, a moderate dry year was manageable. The next dry year will arrive into a fundamentally weaker system, with no equivalent safety valve. The question is not whether another dry year will occur, but whether New Zealand will have the means to withstand it.

Forecasts of gas production are worsening…

13 As shown in Annex 1, this problem has become even more acute due to the rapid decline in domestic gas production.

14 Historically, gas and coal-fired generation have ramped up to supply electricity during dry years. However, coal-fired capacity at Huntly is finite and once fully utilised cannot deliver additional energy. At the same time, the six major gas fields – which together contribute 98 per cent of gas supply – are in sharp decline. OMV announced in April 2026 that the Māui field is expected to cease production this year.

15 As gas supply declines and Māui and Methanex exit, the system's primary circuit breaker – the ability to temporarily redirect gas from industry to electricity – disappears. Counterintuitively, Methanex's departure does not free up gas for electricity. Because gas production cannot readily flex up and down and New Zealand lacks gas storage, any 'excess' gas would be short-lived. Moreover, no other single user can provide equivalent system-wide flexibility and achieving the same outcome would require the simultaneous curtailment of a large number of

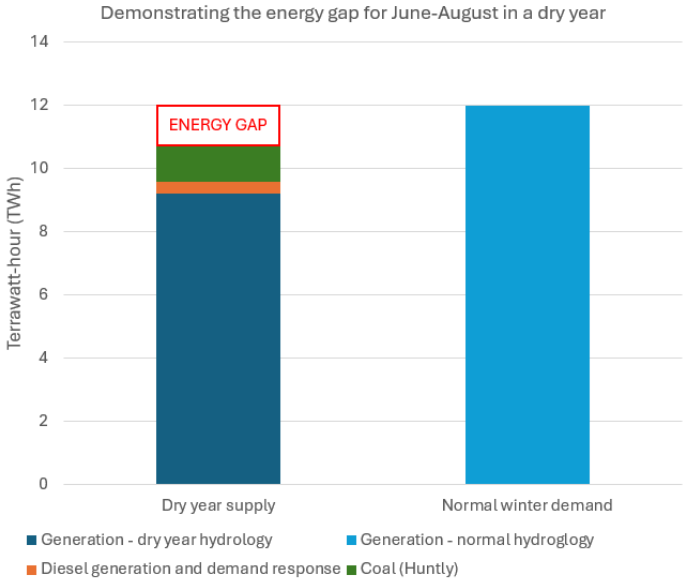
[3] Frontier Economics found this is because (1) the investment needed is so large and (2) the benefits of such investment are system-wide and cannot be fully captured by any single investor.

firms. Put simply: the mechanism that kept the lights on in 2024 is gone. Only new firm fuel supply can replace what is being lost.

16 Industrial gas users[4] have also written to me this month raising their increasing concerns about gas availability. They emphasised they see the LNG import facility as a positive development for energy security and are keen to ensure that LNG will be available for direct use by gas users.

… meaning future dry years will have more severe consequences

17 Looking ahead, the next dry year will arrive in a system with less gas and no material ability to reallocate gas to the electricity sector. New Zealand will be exposed to an energy gap (see figure one).



18 Without a circuit breaker, prices would be expected to rise earlier, remain elevated for longer and reach levels well beyond those observed in 2024.

19 In these conditions, there is no low-cost or contained outcome:

19.1 If gas is prioritised to electricity, large and small industrial gas users would face forced curtailment, leading to production shutdowns, job losses and lost exports. Modelling commissioned by MBIE suggests that compared to a scenario where gas prices continue to rise, an LNG terminal that can effectively cap gas prices would mean GDP is $1.2b better off per annum by 2035. By 2032 the same modelling also shows that 4,900 jobs will be saved by 2032.

19.2 If gas is not prioritised to electricity, wholesale electricity prices could reach extreme scarcity levels, with a genuine risk of an official conservation campaign and – if shortages intensify – rolling outages to preserve system integrity with a risk of scarcity prices of >$20,000/MWh. Unhedged electricity users would face very high prices and may be forced to shut down.

[4] Optima, Fulton Hogan, Dairy Goat Co-operative, NIG Nutritionals, Woolworks, Major Gas Users Group, NZ Bakers Association, NZ Starch, Essity, Whakatāne Mill, NZ Cucumbers, Taranaki Galvanisers, Aluminium Extruders Association, Bioenergy Association and the Carbon and Energy Professionals.

20 Either pathway imposes economy-wide costs: higher energy prices feeding into inflation, reduced household spending, lower business investment and lasting damage to confidence in energy-intensive sectors.

21 This is why every other OECD country that does not have sufficient indigenous gas supply to meet demand,[5] has access to gas imports, either through LNG import terminals or gas pipelines. New Zealand is an outlier – not because our geography makes imports impossible, but because the investment to enable them was never made.

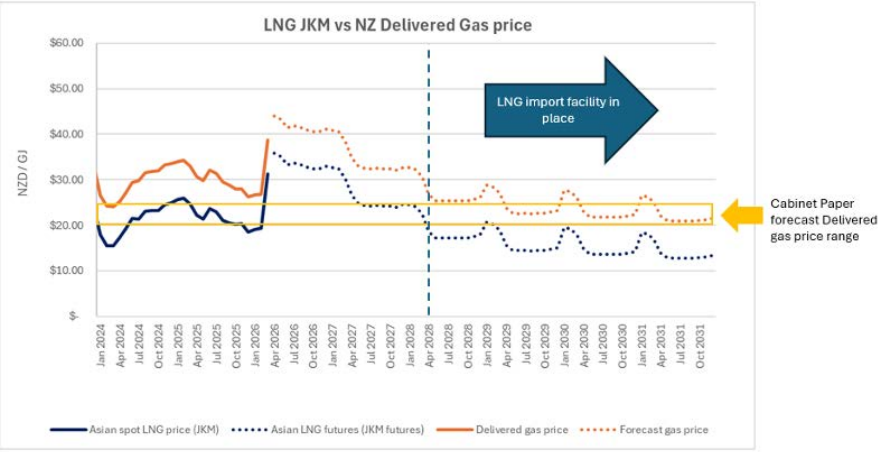
22 In short, declining gas supply has materially reduced the resilience of New Zealand's energy system. Future dry years are likely to be more disruptive, more expensive and more damaging to the wider economy unless new sources of firm, flexible fuel are available to support the electricity system during periods of prolonged low hydro inflows. Coal generation plays an important role but cannot fill the gap alone in a dry year, since the capacity of the Huntly Rankines are a limiting factor.

The Middle East conflict has not significantly altered the case for LNG

23 The conflict in the Middle East has disrupted global energy markets and increased LNG prices, prompting questions about whether the Government's decision to procure an LNG import facility remains appropriate.

24 LNG commodity prices do not affect the cost of the import facility itself, currently estimated Commercial Information As New Zealand will not purchase LNG until the facility is operational, near-term price volatility is not directly relevant to procurement costs.

25 The medium- to long-term outlook for global LNG supply remains broadly positive. In particular: 2026 was already expected to mark the beginning of a period of global LNG oversupply; the IEA expects cumulative new supply over 2026–2030 to materially outweigh volumes lost through the Strait of Hormuz; and LNG futures prices for 2028 and 2029 remain consistent with the price assumptions used in earlier Cabinet analysis (Figure 2).



[5] Austria, Belgium, Canada, Chile, Colombia, Costa Rica, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Korea, Latvia, Lithuania, Luxembourg, Mexico, Netherlands, Poland, Portugal, Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Turkey, United Kingdom, United States. While not yet operational, Australia has completed construction of an LNG import terminal in New South Wales and is planning further terminals in Victoria and South Australia.

26 While short-term volatility has increased, market expectations for LNG prices at the time New Zealand would be purchasing LNG have not materially changed. Long-term contracts and diversified sourcing strategies can further insulate buyers from price fluctuations.

27 The counterfactual is also relevant. Without LNG, New Zealand faces very high domestic gas prices — PWC forecasts $31/GJ as domestic supply declines — alongside costly electricity shortages. The near-term alternative to addressing dry year risk is expensive diesel generation (see next section).

28 MBIE advises that Middle Eastern developments do not significantly alter the case for LNG. Securing an additional fuel source strengthens energy diversity and security at a time of heightened global uncertainty.

An LNG import facility remains the most cost-effective dry-year solution

29 To support the December Cabinet paper, MBIE considered 11 options for dry year cover, 5 of which were shortlisted based on a set of criteria (including being deliverable by 2030 at the latest, using proven technology and being able to deliver 1.5TWh of cover over three months). On this basis, development of an LNG import facility was preferred (see Annex 2). Relative to other shortlisted options, LNG offers:

29.1 **Speed***:* it can support electricity generation from 2028, ahead of most other options.

29.2 **Material reductions in electricity prices:** it provides dry-year cover at relatively low generation costs (around $200–$250/MWh), which would materially reduce wholesale electricity prices during dry years from current scarcity-driven levels.

29.3 **Flexibility:** it has the flexibility to meet unpredictable dry years and does not lock the electricity system in to new long-lived assets (versus building new Rankines, for example, as it uses existing generation kit).

29.4 **System-wide benefits:** it can provide natural gas to industrial users and other businesses while they consider their longer-term energy needs.

30 MBIE advises that LNG remains the most cost-effective option. Since the Government announced it would procure an LNG import facility on 9 February, electricity forward prices for 2028 and 2029 have been around $20/MWh lower than pre-announcement levels. This translates to electricity cost savings of up to $800 million per annum for the economy. Market commentary has explicitly linked the reduction in forward prices to the LNG announcement, including:

30.1 Enerlytica, which has reported that declining forward prices indicate the market is signalling early support for the LNG facility and its risk-mitigation role.

30.2 Forsyth Barr, which has noted that the LNG facility announced on 9 February appears to have been a key factor in the decline in 2028 and 2029 ASX electricity futures prices.

31 The total annual wholesale energy costs in New Zealand is ~$6.5 billion. The annual cost of the LNG terminal is a small fraction of this, and even more so in the context of the total expected investment in the pipeline for renewable generation, which runs into the 10s of billions of dollars.

32 The second-best option to deliver a dry-year solution quickly is to invest in more diesel generation. Diesel generation has a very high generating cost of around $550/MWh prior to the Middle East conflict. As of 13 April, this cost has increased to around $940/MWh following ongoing international supply issues. This is well over twice the cost of LNG generation, meaning diesel generation would put minimal downward pressure on forward contract prices. Moreover, the amount of diesel required would be significant – 27 per cent of New Zealand's daily diesel needs.

The sector is failing to deliver sufficient dry-year cover

33 MBIE advise the sector is unlikely to invest in LNG this decade given significant coordination challenges and misaligned incentives. In 2024 and early 2025, a private sector consortium comprising Clarus and the major electricity generators commissioned reports from Gas Strategies (a UK based consultancy) on LNG import options.

34 The key conclusion from these reports was that, while importing LNG into New Zealand appears technically feasible, "no single location in New Zealand has the existing combination of sufficient water depth, benign metocean condition and existing gas pipeline capacity to meet demand scenarios. Therefore, all locations will require financial investment to address one or more of these issues." The sector noted that *an LNG import option was more challenging than anticipated and that government support would be needed for any option to proceed.*

35 In the absence of Government coordination to overcome these market barriers, it is very possible that the electricity sector will invest in *some* dry-year cover, potentially in the form of diesel peakers and further "demand-response" deals with industry. But this is likely to be patchy, more expensive than LNG (as discussed above), and not of a scale to sufficiently reduce dry year risks and bring down prices. **Investment is likely to fall short of what the economy needs**, when compared with the costs to the economy of electricity shortages. For example, Channel Infrastructure's proposed 72MW diesel peaking plant at Marsden Point would be helpful for system reliability, but modest relative to the scale of New Zealand's dry-year energy shortfall.

Confidential advice to Government

36 If LNG is to be available this decade, Government will need to play a role in *enabling* delivery given coordination challenges. However, the Government has been clear that responsibility for managing dry-year risk sits with the electricity sector, not the Crown.

37 The sector should be responsible for paying for the import facility, consistent with their responsibility for managing dry-year risk. Confidential advice to Government

Confidential advice to Government

Confidential advice to Government

Principles for the funding model

39 The Government (MBIE) will hold the contract with the service provider, and will be responsible for paying the annual service fee. This is because the service providers have indicated that they prefer contracting with Governments for funding certainty (more so in the case of New Zealand given our low levels of demand and distance).

40 The focus of the funding model is how the Government best recovers the cost of the service fee Confidential advice to Government

Confidential advice to Government

41 In addition, options have also been considered against standard criteria, including revenue certainty, efficiency, fiscal neutrality and future proofing.

Options to proceed with funding the LNG import facility

42 The proposed funding approach is aimed at full cost recovery of the annual service fee[6] Commercial Information with the costs of the facility borne by the relevant sector, not the taxpayer. Confidential advice to Government

Confidential advice to Government

[6] The annual service fee is like a charter or lease payment. The LNG Import Facility will be built, owned and operated by the preferred service provider. The preferred service provider will make their own finance arrangements with investors (covering capital requirements), and run the facility. The Government will contract for the services of the facility, and pay the provider an annual service fee (sometime referred to as a charter fee). This is similar to other infrastructure as a service contracts, where the entity receiving the service only pays an annual charge (operating expense), and the service provider bases that fee on recovery of capital costs, return on investment, and operating costs for the service.

Confidential advice to Government

Negotiations

Confidential advice to Government

Options to proceed with procuring an LNG import facility

Two respondents have been shortlisted

45 The procurement process is well underway. Following feasibility assessments, two preferred respondents – Negotiations – have been shortlisted. Both

propose in-port LNG solutions at Port Taranaki, Commercial Information

46 Negotiations

47 Both proposals are capable of delivering 12 PJ of gas over any three months with peak deliverability of 180TJ/day and scheduled availability of 98 per cent over the winter months. This was the minimum functional specification set by MBIE to ensure sufficient dry-year cover. This tends to rule out small-scale facilities which are mostly capable of delivering around 10PJ per annum which is inadequate to provide cover for dry years without needing significant on ground storage. It would also reduce the additional benefit of LNG being available to industrial users as all of the ~10PJ would need to be reserved for dry year cover.

48 The information provided thus far is that the annual cost from Negotiations

49 It is my intention that the Government sign a contract with a preferred LNG facility provider prior to the election, with enabling legislation to be introduced and progressed afterwards. This approach allows additional time for contract negotiations, improving confidence that any agreement reached is robust and value for money, while also providing further opportunity to develop quality enabling legislation.

Negotiations

Next Steps

Next steps to sign a contract before the election and revisit the funding model

52 If Cabinet agrees to continue with procurement Confidential advice to Government the next steps are as follows:

51.1 MBIE would issue a closed RFP in April 2026 to Commercial Information followed closely by the issuing of a draft contract with the provider (in the form of a terminal use agreement or TUA). The issuing of the RFP is currently on hold pending consideration of this Cabinet paper.

51.2 I propose to update the delegated Ministerial Group (Minister of Finance, Minister for Infrastructure, Minister Responsible for RMA Reform, Minister for Resources and Minister for Energy) in July 2026 on progress of the procurement and funding options.

Negotiations

53 In parallel work would continue to develop the enabling legislation and to consider options for the model for procuring LNG itself.

Legislative implications

54 Legislative change would be required as discussed in the December 2025 Cabinet paper. This would include ensuring permissions to develop the infrastructure are granted expeditiously, creating a funding mechanism and setting up a framework to support the necessary commercial structure. I intend to issue drafting instructions for an LNG enabling Bill (as per the delegation from Cabinet in December), so that the relevant legislation can be introduced as soon as practicable post-election.

Cost of living implications

55 Evidence suggests the Government's announcement of an LNG facility has already lowered forward electricity contract prices by around $20/MWh over the years 2028-2029, which will ultimately put downward pressure on power bills.

Financial Implications

Project costs

Commercial Information

Commercial Information

LNG import facility

60 As noted above, I intend that the import facility service fee Commercial Information based on shortlisted proposals) should be fully cost recovered, with charges coming into effect from 2028, when the first service fee payment is due. This funding arrangement will, therefore, not be expected to impact on the operating balance on aggregate over the life of the agreement. Confidential advice to Government

61 Officials are also finalising key terms in the Terminal Use Agreement (TUA). Based on the proposed terms, MBIE considers that (for accounting purposes) the TUA is a service agreement and not a finance lease. Confidential advice to Government [7]

62 As the Government has agreed to the facility and the fiscal impact can be reasonably quantified it will need to be reflected in the fiscal forecasts included in the *2026 Budget Economic and Fiscal Update*. The appropriation implications from the agreement will be sought once there is more certainty around costs.

Treaty of Waitangi

63 MBIE is undertaking Treaty Impact Analysis, with no settlement implications identified to date.

64 Confidential advice to Government Commercial Information Subject to Cabinet decisions, MBIE will begin engagement with relevant iwi.

[7] A finance lease is considered a form of borrowing and is determined based on the level of control a contract bestows on the counter-party. If the TUA was determined to be a finance lease, it would add something in the order of Commercial Information

Regulatory Impact Statement and Climate Implications of Policy Assessment

65 Regulatory impact, cost recovery, and climate impact analysis have previously been provided to Cabinet on the LNG project.

Population & Human Rights Implications

66 There are no population or human rights implications.

Use of External Resources

67 No external resources were used in the writing of this paper.

Consultation

68 The Treasury was consulted. DPMC (Policy Advisory Group) was informed.

Communications

69 I intend to proactively release this paper and the accompanying minute, subject to appropriate redactions.

Recommendations

The Minister for Energy recommends that Cabinet:

1 **note** that in December 2025 Cabinet agreed to procure liquefied natural gas (LNG) services and a procurement process is well underway [CAB-25-MIN-0466 refers];

2 **note** that forecasts of gas supply are worsening, meaning future dry years will have more severe consequences;

3 **note** that recent geopolitical developments have increased short-term LNG market volatility, but

3.1 do not affect the cost of the LNG import facility

3.2 are not expected to materially change LNG price assumptions at the time imports would commence and

3.3 do not affect the insurance value of having an LNG import facility (reducing forward prices by ~$20/MWh);

4 **note** that LNG remains the most cost-effective option for addressing dry year risk by 2030;

5 **note** that LNG import capability will not be advanced by the private sector in the foreseeable future due to a series of co-ordination and utilisation risks;

6 **agree** to progress to the next stage of the procurement process, which is for MBIE to issue a Request for Proposal to the two shortlisted Respondents;

Confidential advice to Government

Confidential advice to Government

Commercial Information

Confidential advice to Government

Next steps on procurement and legislation

14 **note** that there is a risk the procurement process does not identify a suitable commercial LNG arrangement;

15 **note** the Minister's intention that the Government sign a contract with a preferred LNG facility provider prior to the election, with enabling legislation to be introduced and progressed afterwards;

16 **invite** the Minister for Energy to report to Cabinet Negotiations on the selection of a preferred provider;

Financial recommendations

Commercial Information

18 **agree** that the proposed changes to appropriations for 2025/26 above be included in the 2025/26 Supplementary Estimates and that, in the interim, the increase be met from Imprest Supply.

Hon Simeon Brown
Minister for Energy

Annex One: Updated Problem Definition A3

MINISTRY OF BUSINESS, INNOVATION & EMPLOYMENT
HĪKINA WHAKATUTUKI

A dry year without gas becomes an economic crisis

Dry years already cause extreme electricity prices. In future, the consequences will be much more severe

1. WE RELY ON RAIN MORE THAN MOST PEOPLE REALISE

- Around 60% of our electricity comes from hydro.
- Hydro storage lasts weeks, not seasons.
- Every few years, rainfall is low for long enough that lakes steadily drain.
- You only know you have a dry year once the water is already running out.
- Dry years are inevitable and cannot be predicted—only endured.

Dry years are inevitable and cannot be predicted—only endured.

2. IN THE PAST, DRY YEARS WERE PAINFUL BUT MANAGEABLE

In the past, when hydro ran low:

- Coal plants ran hard.
- Gas plants ran for weeks or months.
- One large user (Methanex) could turn off, releasing gas to keep power on.

This acted as a circuit-breaker for the system.

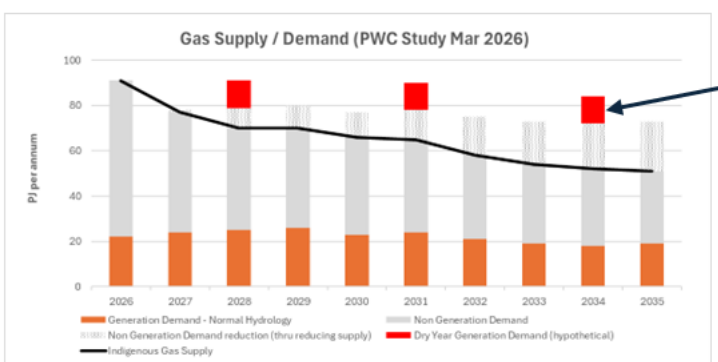
The risk of a dry year increases prices every year:

- Dry-year risk is priced into electricity contracts.
- Meaning it's pushing up household and business power bills every year.

New evidence this risk matters to prices: Electricity contract prices fell markedly after the Government announced the LNG import terminal, reflecting reduced concern about dry-year shortages.

3. THAT CIRCUIT-BREAKER IS DISAPPEARING

- New Zealand's major gas fields are declining rapidly.
- Māui—one of the largest—is now expected to close this year.
- When Māui ceases production, Methanex will have insufficient gas to operate.
- Methanex's exit removes the system's only large, flexible gas buffer.
- New Zealand has:
  - Very limited gas storage
  - No spare domestic supply
  - No alternative generation that can run for weeks or months.



In dry years, additional gas is required for electricity. You only know you need this gas once hydro lakes are already running low.

4. 2024 WAS A WARNING — AND LIKELY THE LAST TIME THIS WORKS

- In 2024 hydro inflows were low (but not extreme).
- Coal ran at maximum.
- Gas generation could not fully run due to fuel shortages.
- The system held only because:
  - Demand turned down (meaning lower GDP).
  - Some firms shut permanently.
  - Methanex curtailed production to shift gas to electricity.
- Even then, power prices spiked from ~$180/MWh to over $800/MWh and economic damage occurred.
- Next time, that fallback will not exist.

5. IN THE NEXT DRY YEAR, THERE IS NO LOW-COST OPTION

If gas is diverted to keep the power on:

- Many gas-using firms lose supply.
- Production shuts down with little notice.
- Jobs and export earnings are lost.
- Costs fall heavily on specific regions and industries.

If gas is not diverted to electricity:

- Power prices rise far higher than in 2024.
- Rolling outages become a credible risk, alongside scarcity pricing (>$20,000/MWh).
- Costs are spread across every household and business.

No other gas user can provide the flexibility Methanex has. It would require simultaneous closure by potentially hundreds of industrial firms.

6. THIS MATTERS BEYOND ENERGY

Sustained energy scarcity does not stay in the electricity sector:

- Firms close or fail to invest.
- Prices flow into food, transport and consumer goods.
- Real wages and household spending fall.
- Economic recovery becomes harder and slower.

2025 impacts of sustained high energy prices driven by fuel scarcity since 2017:

- Reduced GDP by $5.2 billion (1.25%)
- Lowered real wages by 1.4%
- Reduced household spending by 1.65%
- Worsened the trade balance by $275 million

Critically, the damage does not fade quickly: Even short periods of energy undersupply can take up to 25 years for the economy to fully recover, due to lost firms, delayed investment, and persistent employment effects.

Annex Two: comparison of options to provide 1.5 TWh of dry year cover

Score indicates relative ranking of the options against the criteria

	1. LNG import facility	2. Illustrative Rankine option *New power plant with 3 x 250MW Rankines which can use coal or biomass*	3. Illustrative Peaker option *New diesel peakers (300MW) and conversion of 400MW of existing peakers to diesel*	4. Low capex portfolio option *Rankine at Huntly; new and converted diesel peakers; demand response*	5. Additional cover: LNG and Taranaki Combined Cycle (TCC) *LNG, plus TCC refurbished to provide additional generation capacity*
Timeliness	2027 - 2029 (incl. ship build & port works) depending on option *Fast option* *Score: 2*	2030 – 2033 *Slowest option with significant delivery risk* *Score: 5*	2028 *Fast option* *Score: 2*	2028 – 2030s (could be delivered incrementally) *Elements can be delivered quickly* *Score: 2*	2029 *Fast option* *Score: 2*
"Insurance premium" to recover capex	$2.05-$4.10/MWh *Moderate capex option* *Score: 3*	$8.20/MWh *Highest capex option* *Score: 5*	1.20$/MWh *Lowest capex option* *Score: 1*	$2.00/MWh *Low capex option* *Score: 2*	$4.50/MWh *Moderate capex option* *Score: 3*
Cost of generating electricity	$200-$250/MWh *Moderate generating cost – "insurance" puts downward pressure on forward contract prices* *Score: 2*	Coal = $150-170/MWh Biomass=$180 -215/MWh *Lowest generating cost – "insurance" puts significant downward pressure on forward contract prices* *Score: 1*	$510-$570/MWh *Very high generating cost – "insurance" puts minimal downward pressure on forward contract prices* *Score: 5*	Coal: $150-170/MWh Diesel: $510-$570/MWh *Moderate generating cost – "insurance" puts downward pressure on forward contract prices* *Score: 2*	TCC: $155 - $195/MWh Existing kit: $200-$250/MWh *Moderate generating cost – "insurance" puts downward pressure on forward contract prices* *Score: 2*
Flexibility Maintains option value (can exit) Delivers different levels of demand, incl 1.5TWh in dry year	Flexible delivery and adds 4PJ of storage – can readily provide 1.5 TWh over three months Exit-able (FSRU can be sold) Simply provides fuel option, so does not "lock in" generation *Score: 2*	Locks in significant new generation capacity Coal and biomass readily storable so can provide 1.5 TWh over three months *Score: 5*	Locks in new generation capacity, but can be added incrementally Amount of diesel required is significant (27% of NZ daily need) so storage needs to provide the necessary flexibility would be significant *Score: 4*	Locks in new generation capacity, but can be added incrementally Coal and diesel storable. Requires significant diesel storage to be effective as an insurance policy (but less than option 4) *Score: 4*	As per option 1 for fuel source TCC refurbishment locks in generation capacity *Score: 4*
Spillover costs	Risk of exposure to international gas prices (however, domestic gas prices already approaching LNG prices) *Score: 3*	Higher emissions than gas (lower for biomass) Significant new generation plant impacts electricity market (cannot be delivered in small increments depending on need) *Score: 5*	Higher emissions than gas New generation capacity impacts electricity market incentives (lower impact than option 3 as can be delivered in increments) *Score: 4*	As per option 3 New generation capacity impacts electricity market incentives (lower impact than option 3 as can be delivered in increments) *Score: 4*	New generation capacity impacts electricity market incentives *Score: 4*
Spillover benefits	Less emissions than coal-fired generation Potential industrial and commercial use of LNG, maintaining access to gas for those businesses. *Score: 2*	Ability to switch between different fuels improves resilience Regional economic and employment opportunities assoc. with biomass Would release some gas for other users (less than Option 1) *Score: 2*	Limited spillover benefits *Score: 3*	As per option 3 *Score: 2.5*	As per option 1 *Score: 2*

The following table sets out further investment options that were considered, but ruled out at an early stage as not meeting minimum criteria.

Option	Description	Reason for exclusion
Hydro option – North Island	Pumped hydro scheme at Upper Moawhango in the central North Island that could and could add 1.5 TWh to system.	• Sits on defence land (concerns around losing training site); lack of iwi consensus; significant environmental impacts. • Requires major construction - delivery date around 2035.
Hydro option – South Island	Raising Meridian-owned Lake Pukaki by 30m which adds 3.5 TWh of storage.	• Requires major construction - delivery date around 2035.
Distributed demand response	Many large-scale electricity users (e.g. public services, commercials) have their own diesel fuelled back up generation that switches on during power outages. These users could potentially be paid to run their generators during a dry year to provide cover.	• The scale of generation available is likely to be small i.e. not meet or make significant contribution to a 1.5TWh requirement. • There is substantial work required to test the technical feasibility, including co-ordination and payment for this form of demand response.
Geothermal for dry year cover	New geothermal generation targeted to dry year: • Generation to operate at reduced capacity in normal years (for operational reasons). • At an increased output mode in dry years to make up for the reduced hydro output.	• Holding cheap, renewable energy in reserve would be a significant departure from the current market model (where the cheapest form of generation is used first). • There would be (perceived) credibility issues about limiting deployment to dry years. This could have a chilling effect on investment, both in renewables and firm generation.
Lithium ion and other battery storage	Use grid scale battery energy storage systems for short term storage, load shifting and arbitrage. Using large utility scale or aggregated distributed batteries.	• This type of technology has not progressed sufficiently to meet long-duration cover needs. Grid-scale batteries typically store energy equivalent to 2 to 4 hours discharge at the rated capacity. This is a good technology for peaking requirements, or re-distributing solar production, but will not (yet) meet New Zealand's dry year cover requirements.
Rooftop solar	Incentivise significant rooftop solar uptake across residential, commercial and industrial users	• Will not provide substantive additional energy during winter, when we are most likely to experience the dry-year problem.

Confidential advice to Government