EnergyWatch

The Journal of the Sustainable Energy Forum Inc.

Facilitating the use of energy for economic, environmental, and social sustainability

Published by: - The Sustainable Energy Forum Incorporated, M309, 9 Queen Street,Warkworth,0910
Email: -info@sef.org.nz Web: - www.sef.org.nz; and www.energywatch.org.nz

The Sustainable Energy Forum Incorporated (SEF). was reregistered as 1235979 under the Incorporated Societies Act 2022 on 23rd March 2026.
The SEF charity registration number is CC36438.

Issue 87 – August 2026

author: Steve Goldthorpe

ISSN 1173-5449 (print) ISSN 1179-4054 (online)

Special single issue edition

LNG – Why? – How? – Where? – What if? – and Why Not?

The indigenous supply of natural gas in New Zealand is declining in accordance with Hubbert's bell-shaped curve, which predicts the production of a finite resource over time. The peak of natural gas availability towards the end of the 20th century will reduce in the first half of the 21st century. That decline matches NZ's Climate Change obligation to phase out the use of fossil fuels. But it needs to be managed[1].

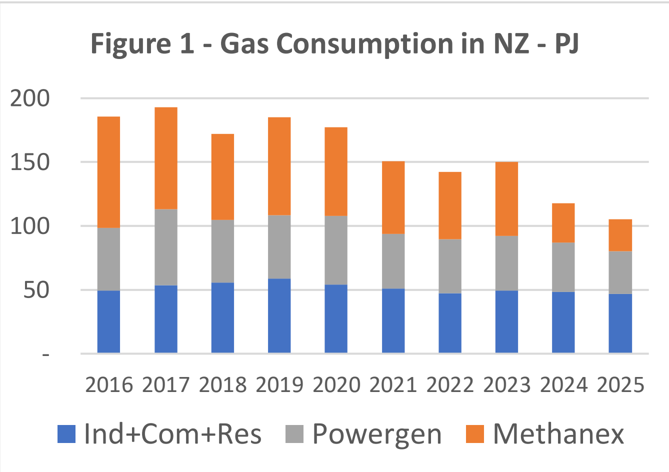


Figure 1[2] shows the natural gas consumption in New Zealand over the last 10 years. When natural gas was plentiful in New Zealand about half of it was bought by Methanex to make methanol for export. Recently, the Methanex gas take has reduced due to declining availability and the imminent closure of the Maui gas field. Although Methanex has gas supply contracts to 2029, it may cease operations before then and sell its remaining gas entitlements to other gas users. **Therefore, there is likely to be adequate gas supply for power generation in the near term without importing LNG.**

Furthermore, the efficient Taranaki Combined Cycle (TCC) gas-fired power station has reached the end of its life. The resulting reduction in the gas demand for power generation matches the reduction of natural gas availability for power generation in the long term. The other efficient gas fired power station is the 400 MW E3P combined cycle power plant at Huntly, which with hydro and coal, helps with wind farm firming.

The traditional role of natural gas in power generation is in fast-start peaking gas turbines to provide on-demand load following capability. However, the rapid technology advances and cost reduction in batteries is a game changer. Solar farms with DC-linked grid-scale batteries are being built around New Zealand with the capability to provide instantly dispatchable AC power at scale to replace the inefficient gas peakers.

Accordingly, early phasing out of Methanex and a reduction in routine gas demand for power generation in the medium term, leaves the remaining indigenous gas for industrial, commercial and residential uses.

[1] Review of proposed dry-year reliability obligation. Concept Consulting. 20 July 2026

[2] Source: - MBIE gas quarterly – Dec 2025 – Gas use for energy in chemical production is reported separately from gas use for non-energy purposes. This chart is compiled on the basis that the listed non-energy values refer to the chemical conversion of gas to methanol. The additional energy use by Methanex is estimated as 50% of the chemical feedstock

CONTENTS

LNG – Why? – How? – Where? – What if? - and Why Not

EXECUTIVE SUMMARY

Natural gas is often the marginal dispatchable fuel for electricity generation, which sets the high price paid to all generators on the spot market in New Zealand. The electricity industry has an economic incentive to maintain that status quo. Routinely supplementing the declining indigenous gas with expensive LNG at small-scale has been assessed.[3] Small-scale imports of LNG would increase electricity prices and profits.

Instead, coal[4] in one unit at Huntly, complemented by dispatchable solar-with-battery systems, could replace gas in that grid-balancing, price-setting role, until there is a radical change in the NZ electricity spot market mechanism.

However, rather than regular small-scale imports of LNG, the Government's plan is irregular large-scale imports of ~15 PJ in dry-years[5] to make 1.5 TWh of backup power. Their declared aim is to avoid electricity supply crises, such as in 2024.

The 2024 problem was as much an artefact of the incentive mechanisms of the electricity and gas markets as it was the consequence of a dry year event. An energy reserve for 1 TWh of generation could cover any credible dry-year events. Two ring-fenced units at Huntly[6] could meet that need.

So, LNG is not needed either at small-scale to keep gas in the electricity market, or at large scale for belated energy supply for a dry year event.

Other issues

LNG technology is used world-wide for trading gas from countries with surplus gas to other countries that need it. However, it is a complex and expensive cryogenic process, which is subject to geo-political upsets. Most LNG is traded on long term contracts. The only country able to supply large-scale LNG on demand is the USA. LNG sourced from the USA can have a greater overall greenhouse gas footprint than coal.

A Floating Storage Regasification Unit (FSRU) is planned to be moored to the main breakwater in Port Taranaki, taking 4 PJ deliveries from large-scale LNG carriers. However, the harbour is not deep enough at low tide to accommodate the large-scale LNG vessels. Extensive excavation and a heavy duty wharf would be required.

LNG is inherently hazardous, particularly when being transferred from an LNG carrier to an FSRU. The main safety measure used by the LNG industry is the imposition of exclusion zones when ships are unloading. The absence of residential areas within two kilometres of an LNG import facility is the norm. In New Plymouth there are existing residential areas within one kilometre of the proposed FSRU location.

In the event that one of the spherical LNG tanks were to fail and spill its contents into the harbour, a dense cloud of methane three metres high would form above the water. If the edge of that cloud were to encounter a point of ignition, a large fireball would result. A speculative radical concept of a FlareFence, which might keep such an event within the port area, is in an t Appendix.

In conclusion:-

- The natural gas decline can be managed
- LNG is not needed for dry-years
- LNG import is strategically undesirable
- Port Taranaki is unsuited to LNG import.

[3] https://cms.clarus.co.nz/assets/Uploads/PDFs/LNG/Public-Release-NZ-LNG-Addendum-on-Small-Scale-LNG-1.pdf

[4] From NZ replaced by torrefied wood in due course

[5] https://cms.clarus.co.nz/assets/Uploads/PDFs/LNG/Public-Release-NZ-LNG-Import-Feasibility-Assessment-1.pdf

[6] Quantifying the "dry-quarter" issue in NZ, EnergyWatch 85, SEF, July 2022.

Why ? - The dry year issue and the NZ electricity market

The principal stated reason for the Government's plan to create an LNG import facility is to provide an energy source that can sustain electricity production in the event of low hydroelectric generation resulting from a dry hydrological year.

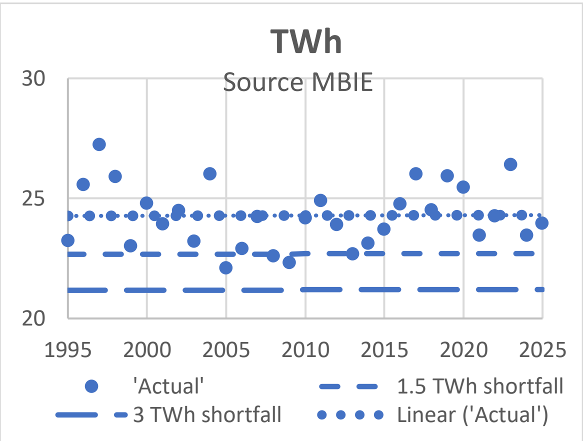
This position was clearly described recently by the Minister of Energy.[7]

> "MBIE advises me that in a dry year the shortfall we need to cover is around three terawatt hours over three months. Assuming that coal can fill 1.5 terawatt hours, thanks to the Huntly firming options that have been put in place, this leaves a remaining 1.5 terawatt hours required to be covered."

Shortfalls in hydro-generation

Figure 2 shows annual hydroelectricity generated in each of the last 30 years, which is a proxy for available rainfall. Water storage is limited.

Figure 2. NZ annual hydroelectric generation



The upper line shows that the average hydro-generation was 24.2 TWh, which is 51% of the total installed capacity. This chart shows that in 2008 and 2013 the shortfall in hydro-generation was 1.5 TWh below average, as indicated by the middle line. 2005 and 2009 had larger hydro shortfalls of 2 TWh. A worst case was 1992. **None of the last 10 years had a hydro shortfall greater than 1 TWh.** In particular, hydroelectric generation in 2024 was only 0.8 TWh below average.

Interdecadal Pacific Oscillation[8]

Research by NIWA has identified long term trends in factors affecting NZ rainfall and wind. Such information can assist with long term planning to allow for hydro and wind variability.

Shortfalls in wind generation

Figure 3 shows quarterly wind yields from 2005 to 2025 compared with trend lines based on installed wind turbine capacity, 36% average load factor, and the average fraction of wind power generated in each quarter[9].

Figure 3 – Wind variability TWh 2005-2025

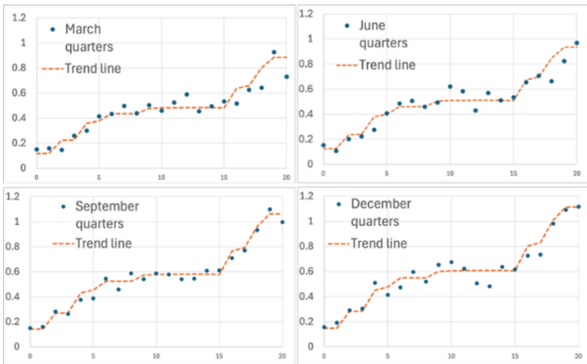


Figure 3 shows that wind power is normally within 10% of the predictable trend. The worst case shortfall in quarterly wind generation was less than 0.2 TWh. The calmest year was 2023 with 12% (0.4 TWh) annual wind shortfall.

The MBIE value of 3 TWh shortfall

This dates back to the arguments put forward by MBIE to ministers for the Lake Onslow project.[10]

> "At its worst, the shortfall of annual inflows has been the equivalent of 5 TWh of electricity lower than average. A more typical dry year has around 3 TWh of shortfall."

[7] Minister of Energy – Hon Simeon Brown – 9th June 2026 to Auckland Chamber of Commerce

[8] https://niwa.co.nz/climate-and-weather/climate-present-and-past/southwest-pacific-climate/interdecadal-pacific-oscillation

[9] 22% in March quarter, 23% in June quarter, 27% in September quarter and 28% in December quarter.

[10] Hon Dr Megan Woods, - Cabinet paper – Update on the NZ Battery project 5th August 2022

In a recent statement from MBIE the 3TWh shortfall is now described as: -

> The 3TWh shortfall scenario calculates the energy deficit caused by these factors combining simultaneously: -[11]
>
> - **Once-in-a-generation dry year:** A severe drop in rain and snow-melt, which significantly reduces the water levels in hydro lakes (New Zealand's primary energy storage).
> - **Low wind generation:** Extended periods of calm weather, limiting the output of wind farms.
> - **Low thermal availability:** Reduced output from coal and gas-fired power plants, driven by aging power stations and declining domestic gas supplies.

The analysis in Figure 2 indicates that the dry-year shortfall has not exceeded 1 TWh in the last 10 years. The worst case dry-year shortfall less than 3 TWh, was 34 years ago. Figure 3 shows that the additional contribution of wind power variability to generation shortfall could be up to 0.4 TWh. Short-term equipment failures could be accommodated by the Whirinaki diesel plant, as occurred on 4th August 2026.

In view of these considerations, looking forward, it would be reasonable to provide for a credible dry-year generation shortfall of 1.5 TWh not 3 TWh. As the Minister of Energy explained that dry-year shortfall can be addressed by the Huntly firming options that have been put in place.

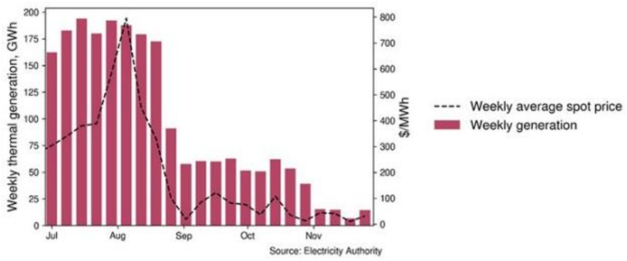
Therefore, importing of large amounts of LNG, to provide occasional additional thermal energy to meet any credible dry-year scenario, is not needed.

What happened in the winter of 2024 ?

In August 2024 the spot price of power on the NZ electricity market rose to over $800 per MWh for about 2 weeks. That caused a power price crisis, particularly for those industries that are exposed to the electricity spot market.

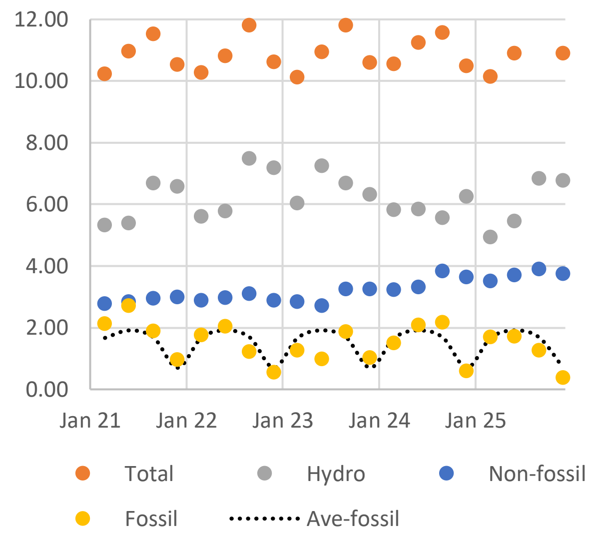
Figure 4 shows that over July and August 2024 the thermal generators produced 175 GWh per week, equivalent to 1000 MW of generation from coal, gas and diesel running full time.

Figure 4. Weekly average spot price and thermal generation, July - November 2024



The installed thermal capacity was 2115 MW, comprising 750 MW of coal, 760 MW of gas combined cycle, 450 MW of gas peakers and 155 MW of diesel. The coal stockpile at Huntly was low. MBIE data infer that the gas supply or plant was constrained. So the Whirinaki diesel plant was used. The dotted line on Figure 4 shows the prolonged high spot price in mid-August.

Figure 5. Quarterly electricity generation - TWh



In context, Figure 5 shows data from the quarterly reporting by MBIE. The upper orange line is the total electricity demand for NZ, which is high in the winter and lower in the summer. The middle grey line shows the amount of hydroelectricity generated in each quarter. The blue line shows the non-fossil power generated from other

[11] MBIE website

sources, including geothermal, wind, solar, and biomass, which has steadily increased over the last 5 years. The gold line shows the generation from coal, oil and gas. The dotted black line shows the quarterly generation from fossil fuels, averaged over 5 years, to indicate the typical use of dispatchable fossil fuels to balance the grid.

Figure 5 shows that in 2024 the winter increase in hydro output was less than usual, resulting in a shortfall over the July to September quarter less than 1 TWh. In that quarter the output from geothermal and wind sources actually increased by about 0.5 TWh, leaving a 0.5 TWh shortfall to be made up by fossil generation.

The MBIE quarterly data shows that the required additional fossil generation was provided almost entirely by coal burning at Huntly power station. From mid-August, Methanex stopped production and sold their gas allocations to power generators. However, there is little indication in the MBIE data that gas-fired power generation was different from normal during the July to September period.

In view of the declining natural gas resource in New Zealand, the future value of indigenous storable gas, is greater than its value for power generation on the spot market. Therefore, it is commercially beneficial for gas fired power generation to be withheld from the spot market, or only offered at a very high opportunity-cost price.

The MBIE data shows that coal-fired generation at Huntly power station was elevated by about 0.2 TWh above average in the April to June quarter in 2024. This may have been in response to the expectation of lower than normal winter hydro availability. In the July to September quarter the use of Huntly power station was elevated by 0.5 TWh above average, but due to reducing stocks of coal, Genesis was apparently unable to further increase coal-fired power generation at Huntly.

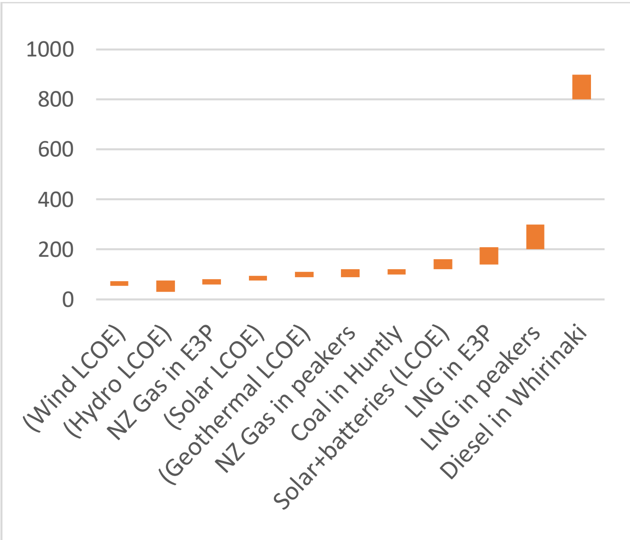
During the July to September quarter 0.02 TWh was generated from diesel fuel in the emergency 155 MW generator at Whirinaki, which is normally not operated at all. This corresponds to 130 hours of operation of Whirinaki at times of peak demand. At a diesel price of $2/litre, the fuel cost of operating Whirinaki power station is $600 to $700 per MWh. The peak electricity spot price rose to over $800 per MWh for a period of about 2 weeks in August 2024. This suggests that Whirinaki became the marginal supplier bidding into the grid at that time.

Although the contribution of 155 MW from Whirinaki is only about 3% of the total electricity demand, the NZ electricity market mechanism sets the spot price of electricity at the price of the marginal (most expensive) electricity generator that has to be dispatched to match demand, which then becomes the price paid to all generators delivering electricity into the spot market. This tail-wagging-the-dog mechanism in the NZ competitive electricity market results in large profits for all generators supplying the spot market, resulting in very high prices for industries without fixed price supply contracts.

Figure 6 shows a comparison of the fuel costs of thermal generation options, with the levelised cost of electricity of the main renewable energy sources. These are the minimum prices at which these players would theoretically bid generation capacity into the competitive market.

Figure 6. Cost of fuel for thermal generation compared with LCOE for renewables

(excl. transmission, distribution and retailing)



In summary, the peak electricity spot price in August 2024 resulted from low coal stocks at Huntly and constrained gas generation, so that diesel generation had to be used. Figure 4 shows that at the end of August, when high-priced gas from Methanex became available, the demand for thermal generation also reduced to less than half of its high level. Diesel generation was not needed. The electricity spot price normalised

The Huntly firming option

In his justification of the need for LNG on June 9th (quoted above), the Minister of Energy referred to the Huntly firming option with the capacity to supply an additional 1.5 TWh of electricity on demand in a dry year. That could involve two of Huntly's three Rankine units being run 24/7 for 125 days (4 months) That capability would require the availability of a stockpile of 650,000 tonnes of coal[12].

The experience in 2024 was that a modest dry-year shortfall coincided with an inadequate stockpile of coal at Huntly, which allowed gaming of the competitive electricity market to create excessively high electricity prices. To avoid that scenario, in 2025 a large stockpile of coal at Huntly was established and funded, via an agreement between the electricity gentailers.

Figure 7. Huntly coal stockpile in June 2026

This dry-year reserve arrangement necessitates a change in the role of Huntly from being one of several contributors to the competitive electricity market, to two of the three units being ring-fenced as back-up generators to provide a security-of-supply service. That service would need to be paid for when it is just on standby.

In due course, gradually replacing the coal stockpile at Huntly with a stockpile of black torrefied wood pellets could address the climate change concerns of burning coal.

Meridian's Lake Pukaki

Meridian Energy has just been granted permission to temporarily lower the water level in Lake Pukaki by 5 metres under some circumstances. That amount of water can generate about 0.5 TWh of electricity. The conditions under which that new licence can be exercised include responding to severe shortages in electricity generation.

Lowering the level of Lake Pukaki has some undesirable local effects, but the access to an additional 0.5 TWh of hydro generation on the rare occasions of extreme electricity shortage could support Huntly power station as New Zealand's main back-up generator.

The Electricity Authority perspective

A recent article from the Electricity Authority (EA) discusses *"Breaking the link between gas supply and electricity prices and what it means for New Zealand's energy future"* [13]

This EA article identifies that the unexpected decline in natural gas supply since 2019 has meant that the market has lost a key source of flexible generation, putting upward pressure on electricity prices. New investment has been entirely on the renewable technologies of geothermal, wind and large scale solar, which is being driven primarily by economics not policy.

The likely outcome is a market characterised by long periods of very low prices, short periods of very high prices and lower average prices over time. Thermal generation is required to fill the gap when renewable generation is low. This matters because over the long run, fuel costs play a major role in determining electricity prices.

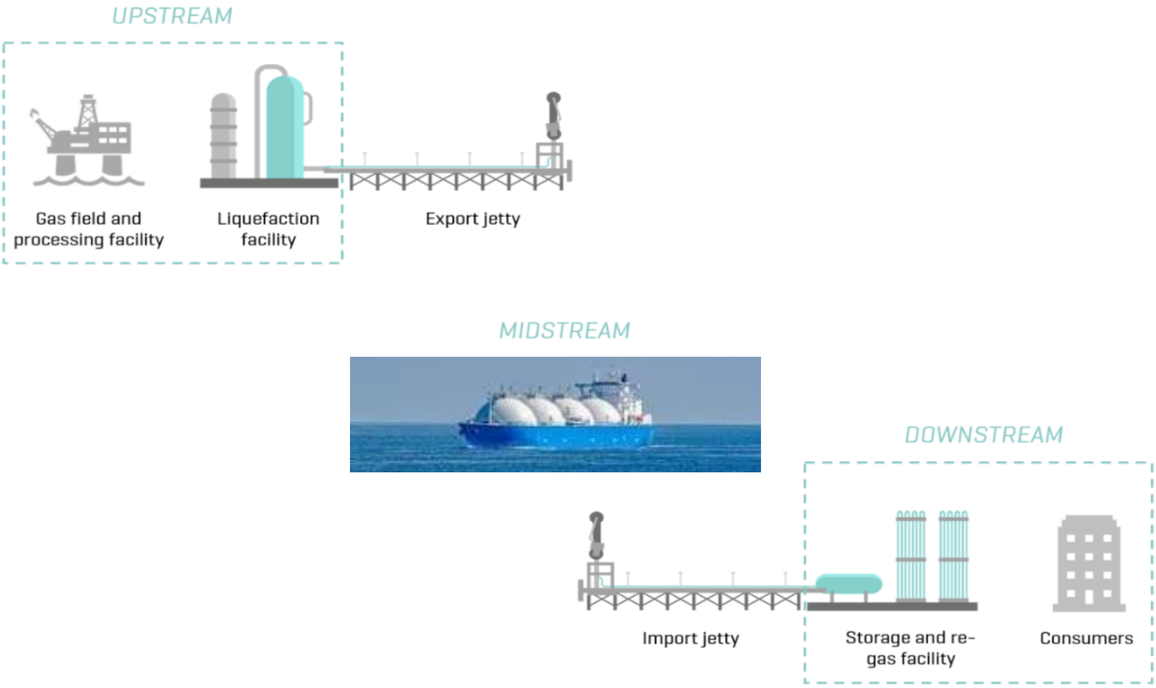
The difficulty is that as renewable generation suppresses average wholesale prices, thermal plants operate less frequently. Eventually plants may struggle to cover their fixed costs and close. The important question is what will provide system wide back-up energy when thermal is no longer available. The next decade will determine how NZ balances affordability, reliability and security of supply as the role of thermal generation continues to reduce.

[12] Coal @ 24 GJ/ tonne and Huntly thermal efficiency = 35%

[13] Hayden Glass, General Manager Wholesale and Supply. 21st July 2026. Market Brief. Electricity Authority

How? – The Technicalities of LNG

Figure 8 LNG gas transportation process train



Ideally natural gas is transported from gas wells to customers by pipeline. However, that is not always practical. For example, a trans-Australia gas pipeline to deliver natural gas from the gas fields off the West coast to the consumers on the East coast of Australia is not sensible.

Figure 8 illustrates the LNG transport process. In the liquefaction facility, pipeline natural gas from the gas field processing facilities is chilled in stages down to -162ºC when it condenses to a liquid. For comparison, the temperature reduction in the multistage LNG production process is more than five times greater than the temperature reduction from 15ºC to -18 ºC by a domestic deep freeze. The Main Cryogenic Heat Exchangers (MCHEs) used in LNG production are highly specialised due to the extreme engineering, metallurgy, and thermal physics required for cryogenic liquefaction.[14]

LNG must be held in highly insulated containers comparable with liquid nitrogen (-196ºC) storage. However, unlike liquid nitrogen, boil-off gas cannot be vented, but must be actively managed. 0.1% to 0.15% per day typically boils off stored LNG in large tanks. The boil-off gas is normally used as fuel for the LNG carrier during the voyage to avoid the need for complex reliquefication equipment on board LNG carriers.

Transfer of LNG from a carrier to a storage tank involves the displacement of methane vapour in the receiving tank and vice versa in the delivery tank. Conducting such transfers in a safe manner is a slow process, taking more than 24 hours.

LNG is hazardous. The danger is typically managed with 2 km exclusion zones around LNG transfer operations. LNG is odourless, so leak detection requires methane monitors. Addition of the mercaptan odourant of gas for reticulation would have to be made during regasification.

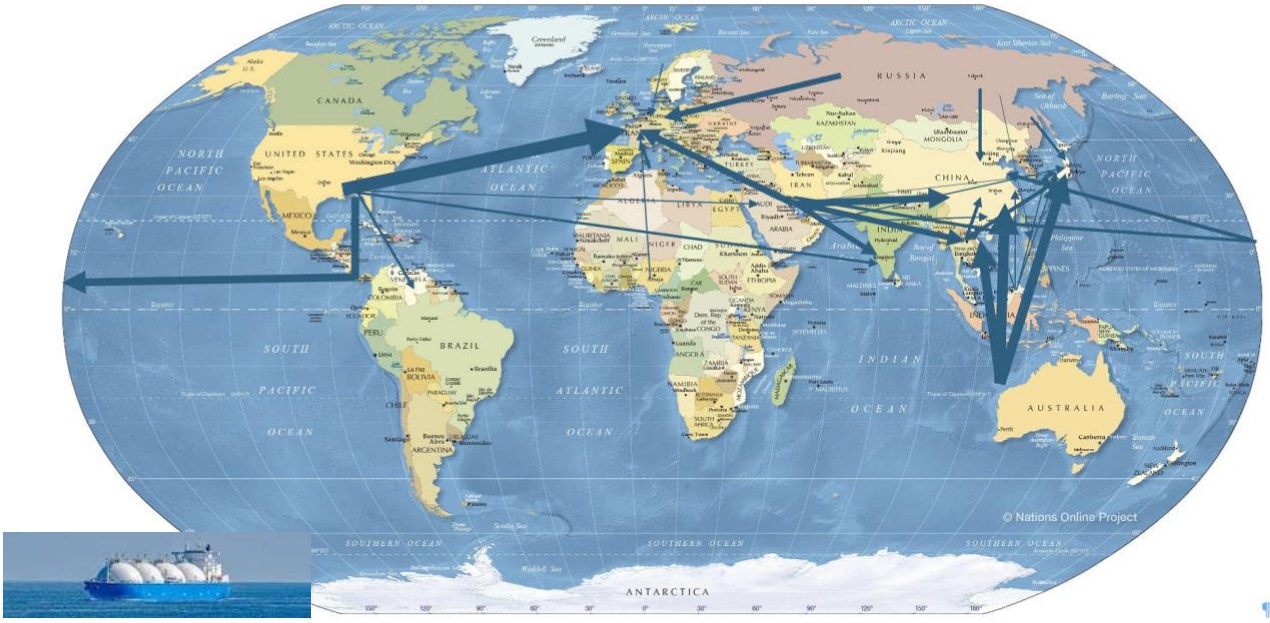
Reheating LNG to gas at ambient temperature needs a source of heat. Seawater is typically used. That process results in the discharge of a large cold water plume back into the sea. Also, chlorine treatment of the regasification equipment to prevent fouling can result in chlorine contamination of the discharged seawater.

[14] https://www.icarus-hex-group.com/applications/lng-heat-exchanger/

Sources of LNG

Figure 9 Main International LNG trades in 2024

Line widths: 1pt = 4 million tonnes LNG per year



Source World bank WITS database

Figure 9 shows the scale of the main international trades of LNG, as they were in 2024. The largest trade is the USA delivering LNG across the Atlantic to Europe. The USA also delivers LNG to Asia via the Panama Canal at the rate of about one large Panamax LNG carrier each day.

LNG from the Australian West Coast is delivered under long-term contracts to import terminals in Asia. So, requests for LNG carriers to be occasionally diverted to meet ad-hoc dry-year needs in New Zealand, would probably have to directed to Singapore rather than Perth.

Until February 28th 2026 the third main supplier of LNG to the global market was Qatar. However. the closure of the Strait of Hormuz following the US/Israeli attack on Iran meant that that source of LNG stopped immediately. Five months later, the production and export of Qatari LNG has not recommenced. Some of the complex LNG production facilities in the Middle East have been severely damaged and may take several years to rebuild after hostilities cease.

Figure 10. History of Major LNG exports[15]

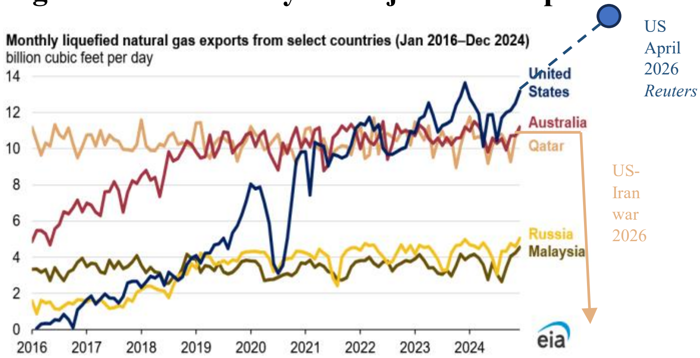


Figure 10 show the history of major LNG exports over the last 10 years. Apart from the USA, exports have stabilised, with annual variation. In contrast the export of LNG from the USA grew from nothing to being the largest supplier over the last decade, with notable variation during Covid.

The sudden reduction of LNG availability from Qatar this year appears to have been partly met by increased production in the USA. This illustrates the ability of the USA to respond to market demands and suggests that the USA might be the only LNG vendor with the capability to respond to ad-hoc dry-year requests from New Zealand

[15] https://www.eia.gov/todayinenergy/images/2025.03.27/main.svg

The Greenhouse Gas footprint of LNG

The combustion of fossil fuels involves the transfer of carbon from the geosphere to the atmosphere as CO_2, where it impacts radiative forcing by a mechanism known as the Greenhouse Effect. Over the last two centuries CO_2 in the atmosphere has gone from 280 ppm to 430 ppm, which has made fundamental long-term adverse changes to the global climate. This is known as Climate Change; formerly Global Warming.

In addition, methane emissions have a strong short term radiative forcing effect. Over a 20-year time frame the greenhouse effect of methane is 84 times stronger per tonne than CO_2. That is known as the Global Warming Potential (GWP) of methane. However, for the agreed international climate accounting methodology, the effect of methane on the climate is assessed on the basis of its effect over 100-years using a GWP value of 28.

When coal, oil and gas are burned to release energy the direct emissions are about 90-96, 73 and 56 tonnes CO_2 per terajoule respectively. Hence gas is more greenhouse friendly than coal. However, the overall Climate Change effect, known as the Greenhouse gas (GHG) footprint of using these fossil fuels, is greater when the emissions from production and transport of the fuel prior to combustion are taken into account.

The CO_2 and methane emissions from the production of coal, oil and gas typically add about 10% to 20% to the GHG footprint of conventionally produced and delivered fuels. However, when natural gas is converted to LNG for international transport, the energy use and methane emissions associated with the additional processes increases LNG's GHG footprint.

In the USA, natural gas production mostly involves hydraulic fracturing (fracking) of old wells and shale resources. About 80% of US gas production now uses fracking, which is a GHG intensive process due to losses of methane to the atmosphere.

Professor Robert Howarth of Cornell university in the USA has published several studies[16] of the greenhouse gas footprint of LNG made from US natural gas that has been produced via fracking.

Figure 11. Greenhouse gas emissions from production and transport of US LNG

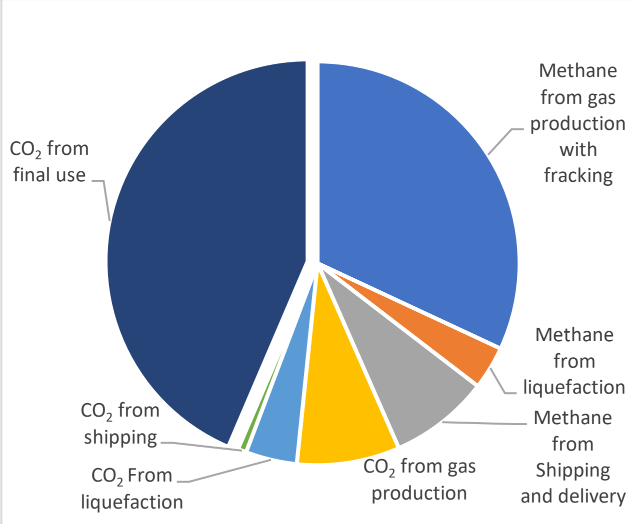


Figure 11 compares the CO_2-equivalent emissions from burning natural gas with the emissions from production of the source gas via fracking in the USA and its transport as LNG. This analysis controversially uses the 20-year GWP factor of 84. On that basis, the methane from fracking dominates the GHG footprint of US-based LNG. With the 100-year GWP factor the gross GHG emission is 97 tonnes CO_2-e/TJ.

The common perception, that natural gas would be more GHG friendly than coal for use as a short-term transitional fuel, is not necessarily valid if the imported natural gas is LNG made from fracked gas produced in the USA.

> In 2011, when working for the IEA Greenhouse Gas R&D Programme, I was commissioned to investigate Prof. Howarth's claims that LNG produced from US fracked gas was as greenhouse intensive as coal. After detailed examination of his data, and my investigation of fracking technologies, I concluded that Prof. Howarth's conclusions were valid. My IEAGHG report was never published.[17] *Steve Goldthorpe*

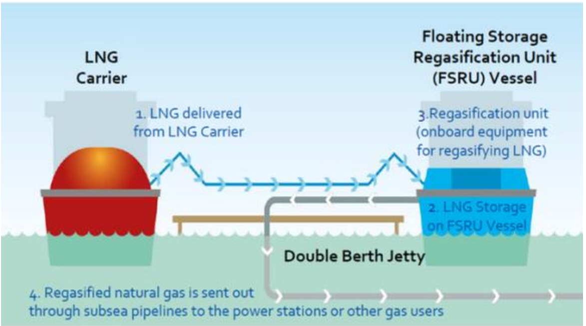
[16] https://scijournals.onlinelibrary.wiley.com/doi/10.1002/ese3.1934

[17] www.sef.org.nz/views/Goldthorpe_ESR_130815.pdf

Where ? – Locations of LNG import facilities

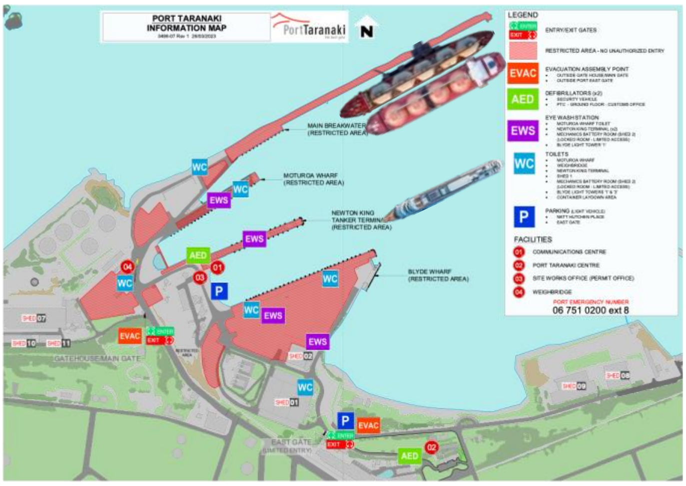
Port Taranaki is the preferred location for the proposed LNG import terminal. It would comprise a Floating Storage and Regasification Unit (FSRU) moored alongside the main breakwater.

Figure 12 The function of an FSRU.[18]



In Port Taranaki, a 300 m long LNG delivery vessel would tie up alongside the permanently moored FSRU beside the main breakwater to make a 4PJ LNG delivery. Figure 13 shows the planned location of these vessels. For comparison a large cruise ship entering the port is also illustrated.

Figure 13 Large scale LNG transfer in Port Taranaki



The complete berthing, connection, LNG transfer and disconnection process with all the necessary safety protocols, takes 24 to 36 hours, which is 2 to 3 tidal cycles. The drafts of loaded FSRU vessels and ocean-going LNG tankers are about 12 metres. To avoid those vessels grounding at low tide, extensive excavation of the north side of the harbour adjacent to the main breakwater would be required with construction of a deep water wharf.

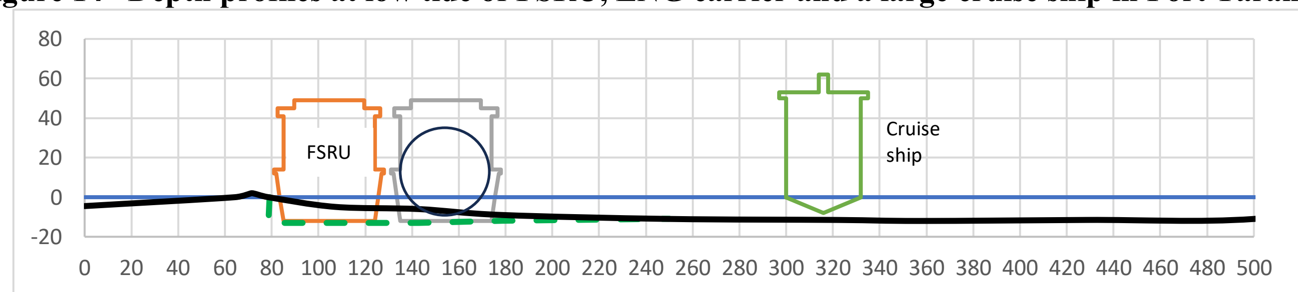
Figure 14 compares the cross sections of a permanently moored FSRU, an ocean-going LNG carrier and a large cruise ship with 8 metres draft, The black line indicates the present depths of the passage between the ends of the breakwaters at low tide, which can accommodate ships with up to 10 metres draft at any stage of the tide.

The green dotted line shows the required excavation of the harbour at New Plymouth needed to create a basin with a depth of 13 meters at low tide to accommodate an FSRU and a visiting LNG carrier for the LNG delivery process. Removal of over 200,000 cubic metres of material would be needed.

Even with entry, manoeuvring and exit of the LNG carrier limited to operation at high tide, extensive civil works would still be needed for the port.

An alternative location for an LNG importing terminal for New Zealand could be Northport, which has adequate deep water berths to accommodate LNG deliveries and is more remote from centres of population. However, the 8-inch gas pipeline to Marsden Point could take 5 months to transfer the gas from each 4 PJ delivery.

Figure 14 Depth profiles at low tide of FSRU, LNG carrier and a large cruise ship in Port Taranaki



[18] Case Study by Michaels Solovovs, Mitsui O.S.K. Lines as reported in Riviera 14 March 2024.

Location of a small-scale LNG import terminal

The alternative of a small-scale LNG import terminal was presented in a 2025 addendum[19] to the 2024 large-scale LNG import assessment report on the Clarus website. This alternative scheme, based on standard 0.35 PJ LNG carriers, is significantly different from the large-scale LNG import terminal for 4 PJ LNG carriers proposed by the Government.

That said, the large-scale scheme would also need a regular small-scale delivery every 3 months to replace the gas boil-off[20] needed to maintain a large-scale FSRU at operating temperature during normal years. That operating requirement would result in the import of 1.4 PJ of LNG every year.

The small-scale LNG scheme alone would not address the Government's perceived dry-year dispatchable energy shortfall scenario.

However, it would address the desire of the electricity industry to sustain the role of natural gas as the marginal supplier and price setter in the New Zealand electricity market. Indeed, LNG would benefit the electricity gentailers by increasing the cost of gas fired generation and thus increasing the electricity prices and the consequent large profits on hydro-generation, which is a feature of the current NZ electricity market structure.

Continuous supply of a constant amount of LNG on a long term contract is the normal mode of LNG trade. A fixed flow rate contract would be priced lower than an on-demand occasional supply.

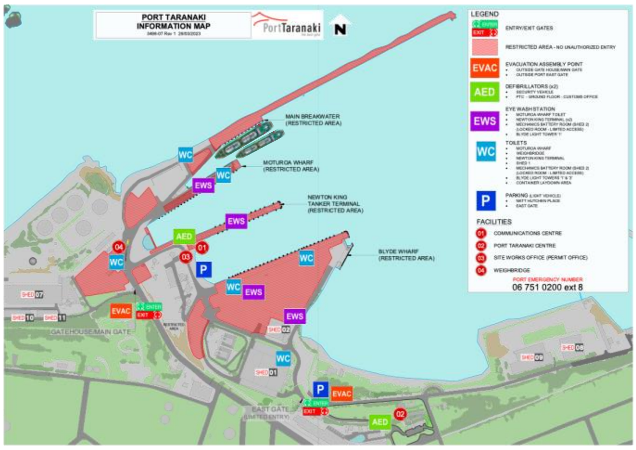
Small-scale LNG tankers are widely used for short distance LNG distribution from major import terminals to more remote locations. In the case of small-scale supply to New Zealand from an East Australian LNG terminal, such as Port Kembla, one 15,000 m^3 LNG tanker could deliver 0.35 PJ on a fortnightly round trip schedule. The standard dimensions of such an LNG carrier are 140 m long and 25 m wide, with a loaded draft of 7 metres.

The associated small-scale FSRU could be moored in a more sheltered location. The role of the FSRU would be to receive a fortnightly 0.35 PJ delivery of LNG, regasify it, odourise it, and deliver it continuously at 24 MMSCFD into the gas reticulation system.

The 8-inch gas pipe line to Marsden Point would have the capacity to deliver 24 MMSCFD of gas with pressure boosting stations. That means that Northport could be considered as an alternative to Port Taranaki for small-scale LNG import.

The small-scale 7 m draft LNG vessels could be accommodated in deep water adjacent to the main breakwater, as shown on Figure 15.

Figure 15 – Small-scale LNG transfer



The risk of a major fire resulting from a spill of LNG would be reduced at the small-scale of operation. The analysis on Page 12 considers the consequences of 20% of the FSRU contents being spilled into the harbour and forming a methane vapour cloud 3 metres deep, which could drift into the nearby residential areas. In the case of small-scale operation, an equipment failure resulting in a spill of 20% of the FSRU contents into the harbour, would produce a cloud of methane less than half a metre deep over the 94 hectares of the harbour. Such a cloud might remain within the harbour as it warms to -100°C, to become buoyant in air and disperse, hopefully without catching fire.

[19] https://cms.clarus.co.nz/assets/Uploads/PDFs/LNG/Public-Release-NZ-LNG-Addendum-on-Small-Scale-LNG-1.pdf

[20] At 0.1% per day of LNG storage capacity, assuming that LNG reliquefication equipment is not installed.

What if? The hazard of bulk LNG

The MBIE website states[21]

- Natural gas and LNG are not toxic. LNG is non-flammable and non-explosive in its cryogenic liquid form.
- Liquid LNG is heavier than air. In the event of a release, it warms and returns to its gas state, which is lighter than air. The gas rises quickly and disperses on its own.

In its cryogenic liquid form, LNG is at a temperature of -162°C. A part full tank of LNG would contain liquid overlaid by methane vapour also at -162°C. A contained system in the absence of air would not have the potential to explode. Large insulated LNG tanks are not pressurised. The hazard of LNG would arise from a spill with the risk of explosion as the methane mixes with air.

The stoichiometric ratio for the combustion of methane in air is 9.5%. However, a flame front will propagate through a methane/air mixture at concentrations between the 5% Lower Explosion Limit (LEL) and the 15% Upper Explosion Limit at ambient temperature. Within this concentration range the methane/air mixture will burn explosively if it encounters a source of ignition. The explosive regime will exist at the interface between the methane cloud and the surrounding air.

In the case of small discharges of methane from routine operations or minor leaks, the risk of explosion is avoided by ensuring that there is no source of ignition present in the vicinity, as the methane disperses to concentrations well below 5% in air. That is achieved by imposing an intrinsically safe exclusion zone with no sources of ignition.

A large spill of LNG

In the event of a major failure of just one of the cryogenic LNG tanks, there is potential for a large amount of LNG to spill into the harbour. LNG liquid has about half of the density of water and would float on the water surface. Rapid liquid to liquid heat exchange would initially occur between the ambient temperature water and the LNG at -162°C. So the water would freeze and the LNG would boil to form a dense cloud of methane vapour at -162 °C. At that temperature the methane cloud would have a density 1.4 times greater than the surrounding air . Heat exchange from the frozen harbour water up into the methane vapour cloud would be slow, so the ultra-cold asphyxiating methane cloud would persist for some time. The methane cloud would need to warm from -162°C to -100 °C to become buoyant in ambient air.

Figure 16 shows an image from a video[22] of the release of LNG at the US DOE Test Centre in the Nevada Desert in 1987. This video shows the fifth of the Vapour Cloud Exclusion Zone "Falcon" tests that were evaluating the effectiveness of vapour control barriers. In this fifth test the methane vapour cloud encountered an ignition source outside the test area. A fire resulted.

Figure 16. Cloud of dense LNG vapour

Failure of just one of the 40 metre diameter spherical LNG vessels might spill 5000 tonnes of LNG into Port Taranaki harbour, which would quickly evaporate into a cloud of 3 million cubic metres of methane vapour. That would form a layer 3 metres deep over the 94 hectares of water in the harbour. An off shore wind could take the vapour cloud safely out to sea. However, an on-shore wind could enable the methane to encounter a source of ignition with disastrous consequences.

[21] https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-generation-and-markets/gas-market/lng-in-new-zealand

[22] https://www.youtube.com/watch?v=O-kEPdAHxN8

Why not? - Conclusions

The Government has been ill-advised by MBIE that NZ will need 15 PJ of LNG in dry-years. That scale of LNG import is unnecessary.

The traditional role of natural gas for peak electricity generation is being replaced by the new technology of low-cost grid-scale batteries.

New renewable generation capacity is being built to meet growth in demand. So natural gas can be phased out of electricity generation as indigenous gas supplies decline.

Firming of renewable generation can be achieved by integrated planning.

The traditional price-setting role of gas in the electricity market, resulting in the unnecessarily high average electricity prices, could be phased out, rather than sustained with expensive LNG.

LNG is neither needed nor desirable for electricity generation in New Zealand

The international trade in LNG is based on long term contracts for continuous supply. The plan for occasional dry-year-only imports of LNG does not fit that trade model, economically or technically.

Ad-hoc supplies of LNG may be available from fracked gas sources in the USA.

When US fracked gas is transported as LNG it has an overall greenhouse footprint greater than coal.

The US/Israeli war on Iran demonstrates that LNG trade is subject to geo-political upset.

Import of LNG is strategically undesirable

The proposed location for a permanently moored FSRU and visiting LNG carriers in Port Taranaki is shallow. Extensive dredging and civil engineering would be required to create a deep-water port facility for LNG import.

The proximity of residential areas to the port is inconsistent with the safety exclusion zones normally imposed around LNG transfer operations.

Port Taranaki is open to ocean swells.

Port Taranaki is unsuited as an LNG terminal

In the event of a large spill of cryogenic LNG, it evaporates to form a dense cloud of super cold methane vapour that slowly warms and eventually becomes buoyant in ambient air. Until then, the interface between the methane cloud at ground level and the surrounding air would be explosive.

The assurances provided by MBIE that LNG is non-hazardous are not valid

Join our sustainable energy news & discussion group

The Sustainable Energy Forum (SEF) is a membership-based organisation founded to facilitate the use of energy for economic, environmental, and social sustainability.

The primary communication medium of SEF is the SEFNZ email news and discussion facility which provides a way to keep up to date with news as it happens and the views of members. The discussion by the group of sustainable energy commentators who respond to the SEFNZ email service offers some interesting perspectives.

Non-members are invited to join the SEFNZ email news service for a trial. To do this send a blank email to: SEF+subscribe@SEFNZ.groups.io or contact office@sef.org.nz.

EnergyWatch

EnergyWatch is an occasional publication of the Sustainable Energy Forum. Archived copies of 85 back issues of EnergyWatch and some other publications are available on the website

www.energywatch.org.nz

While every effort is made to maintain accuracy, the Sustainable Energy Forum and the editor cannot accept responsibility for errors. Opinions given are not necessarily those of the Forum.

Publication is now periodic. EnergyWatch is posted on SEF's EnergyWatch website as a PDF file, shortly after individual distribution to SEF members.

Appendix 1 FlareFence - a radical concept

This radical concept evolved from discussions about how a nearby community might be protected from damage potentially arising from an LNG spill.

The low-probability, high-consequence possibility of a major LNG spill with a subsequent major fire is generally managed by the imposition of an exclusion zone around LNG facilities, particularly during LNG transfer operations. Such exclusion zones are usually industrial areas with access restricted to trained personnel and requirements for intrinsically safe equipment. Residential areas are typically no nearer than two kilometers from large-scale LNG handling facilities.

In locations where those criteria cannot be met, such as Port Taranaki, the safety of the nearby community might be addressed by the creation of a barrier to prevent the effects of a major LNG spill extending beyond the immediate area of the spill.

The 1987 Falcon - Vapour Cloud Exclusion Zone Tests in Nevada were aimed at testing physical barriers able to contain a methane cloud. However, the video of the fifth such test, illustrated in Figure 16, demonstrates a failing in that approach.

An alternative radical approach, based on common industrial practice, is to deliberately ignite fugitive methane early in order to eliminate the spread of the hazard to nearby areas. In addition combustion of fugitive methane reduces its GHG impact.

This radical concept is termed FlareFence.

The FlareFence might consist of five meter high poles spaced every ten metres along the boundary that is to be protected from methane cloud drift. Each pole would be equipped with methane sensors at multiple levels linked to multiple electric spark generators. Such poles might also have the function of providing site lighting.

In the event of any of the methane sensors detecting a methane concentration above 1%, the electric sparks would be activated. At the same time an audible alarm would be activated to warn trained on-site personnel to evacuate the area or to go to fire-proof shelters.

This FlareFence concept would utilise the delay between a spill occurring and the possible subsequent fire, to give on-site personnel time to take action for their own safety.

The Arctic Metagaz incident

An example of that life-saving time delay occurred on 3rd March 2026, when a sanctioned Russian LNG tanker, the Arctic Metagaz, was crossing the Mediterranean Sea. That LNG tanker was attacked by a drone and a large fire ensued.

Figure A1.1 Arctic Metagaz LNG tanker hit by a drone in the Mediterranean[23]

However, it is reported that all 30 crew on board escaped in lifeboats without any loss of life. A delay between the ship being hit and the fire starting could have helped to the crew abandon ship without loss of life.

The Everett Marine LNG terminal in Boston Ma., is within a few hundred metres of residential apartments. This is often cited as an example of an LNG terminal in an urban environment. However, the LNG terminal was built in 1971 and the nearby residences were built later between 1983 and 2009. The FlareFence concept might be useful for resolving that urban planning reverse sensitivity quandary.

[23] https://www.thebarentsobserver.com/news/tanker-attacked-in-mediterranean-was-carrying-sanctioned-arctic-gas/446187