LNG import and options to increase indigenous gas market capacity and flexibility in New Zealand

March 2023

enerlytica

ABOUT THIS REPORT

The Minister of Energy and Resources has asked the Gas Industry Company (GIC) to prepare a Gas Transition Plan. To support its work programme, GIC has commissioned Enerlytica to prepare an independent analysis of the potential role that liquefied natural gas (LNG) imports and additional indigenous gas storage could play in the New Zealand energy sector.

We were asked by GIC to address:

1. How LNG could support natural gas in providing the necessary flexibility (daily, seasonal and dry year flexibility) in NZ during the transition period, including describing:
   - how LNG works, and practical implications with integrating LNG into New Zealand's gas system (e.g. infrastructure, regasification, volumes, commercial considerations)
   - the gaps LNG could fill (e.g. dry year cover, providing flexibility for increasingly peaky gas demand) and the economics of doing so
   - what would be specifically required to import LNG for dry year cover
   - what would be required to establish a local LNG market
   - how other commodity markets (internationally) would feed into commercial decision making in relation to LNG in NZ including methanol, coal, oil, electricity spot prices and LPG.
2. What would be required to develop additional storage (including LNG, LPG, CNG, natural gas or any other viable storage options) at scale to support the natural gas industry / security of supply during the transition, including:
   - physical and technical requirements
   - economic and commercial requirements
   - what timing / lead in would be required.

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Enerlytica counts most of the largest upstream, midstream and downstream energy companies active in the New Zealand energy sector as current clients of its services. Most government and quasi-government entities involved in the New Zealand energy sector are also Enerlytica clients.

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KEY CONCLUSIONS

The Gas Industry Company has engaged Enerlytica to identify feasible options to improve the security of gas supply in New Zealand. We were asked to analyse: (1) the scope for gas to be imported into New Zealand as LNG; and (2) domestic options that could provide additional storage capacity for indigenous gas. Our key conclusions:

Lack of gas import/export flexibility has contributed to gas market stress

New Zealand is the only developed nation with an indigenous gas market that does not trade gas with another nation. This absence of external fungibility is also unique among primary energy fuels within New Zealand as existing infrastructure already enables the international trade of oil products, LPG, biofuels and coal. The result is an inability to balance what is a highly concentrated domestic gas market with external volumes during periods of domestic over- or under-supply. Since the Maui field entered decline in the early 2000s, the market has experienced several such periods of imbalance, including the most recent sequence of a significant supply shortfall since 2018. There is a gas supply gap of up to 65 PJ pa that could have been met by gas if it was available. There are indications this supply gap should narrow significantly in the next 2-3 years, however this is not certain. In addition, the magnitude of the gas supply gap in any one year is highly uncertain, with a large range of possible outcomes depending on hydrological cycles, electricity demand growth, Tiwai Point continuity, new renewable generation capacity additions and the impact of government policy on the future demand for generation gas.

LNG is a viable option for New Zealand and a fit with existing policy settings

LNG has been traded internationally for more than 50 years and there is now a deep and mature global spot market for LNG in the Asia-Pacific region through which cargoes can be imported flexibly. Major advances in floating LNG storage and regasification infrastructure (FSRUs) over the past decade have also dramatically reduced the scale and cost of acquiring import capability. The portability and high degree of technology standardisation that FSRUs offer allows adopters to meet commercial objectives while also avoiding stranding risk when import capability is no longer required. The addition of a FSRU into the New Zealand market would improve security of gas and electricity supply by adding unconstrained dynamic gas feed-in capacity of as little as 2 TJ per day through to as much as 500 TJ per day. It would also serve to provide cover for scheduled and unscheduled upstream and downstream outages, add a new gas wholesaler to the market and to introduce a ceiling price for indigenous gas while meeting government policy targets to end coal-fired electricity generation by 2030 and achieve 100% renewable electricity generation by 2030. The main disadvantage of LNG is that it is more expensive than long-term indigenous gas prices. We identified four potential receiving sites at Marsden Point, Port Taranaki, South Taranaki Bight and as a tie-in to the Maui-A platform. Of these options, Port Taranaki provides the best fit with existing infrastructure but faces significant uncertainty over consenting timeframes and outcomes. Marsden Point is an already-consented site that could be delivered rapidly but faces onshore bottlenecks that would constrain the utilisation and increase the cost of import infrastructure. South Taranaki Bight could be an inexpensive option that would also connect well with existing infrastructure. Maui-A would require bespoke FSRU and mooring modifications that would be expensive to implement.

Domestic storage+flex expansion options exist but are molecule-reliant

Currently the only ability to transparently and dynamically defer the consumption of significant volumes of indigenous gas in New Zealand is provided by the Ahuroa underground gas storage (UGS) facility. Low gas market liquidity and a deterioration in its performance has in recent years however significantly constrained its utilisation. Liquidity constraints are expected to improve from 2023 if indigenous gas supply meets operator forecasts. Options to better balance supply with demand across time include expanding cycling capacity at Ahuroa, constructing a new UGS facility, building LNG peak shaving facilities, paying gas producers to provide standby production and agreeing terms with major users to provide demand-side response. Of these we view a new UGS installation as providing the greatest scope to provide additional system flexibility at the lowest relative cost. We also think there is merit in undertaking further work to investigate options to adopt indigenously produced gas, methanol and/or LPG into either floating or temporary land-based electricity generation to support security of supply in the upper North Island.

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Purpose

This report has been commissioned by the Gas Industry Company to analyse for how LNG could add capacity and flexibility to the New Zealand gas market and to identify options to add storage capacity and flexibility for indigenous gas.

Gas market setting

The New Zealand gas sector is unique among its developed nation peers. It is the only OECD member with a domestic gas market that does not trade gas across its borders. Therefore, by definition, under current infrastructure and arrangements, local market gas supply must always match local market gas demand. During the first three decades of gas market development end users enjoyed the benefit of abundant supply and low prices. Since the turn of the century however supply and demand has become more variable as a series of changes and events have led to extended periods of over- and under-supply and increasing uncertainty. On the supply side, the most recent cycle has been defined by the accelerated decline of the market's largest gas field at Pohokura which, compounded by a string of weak hydro inflow sequences, has produced extended periods of constrained gas and electricity supply and consequently high wholesale energy prices. On the demand side, increasing penetration of intermittent renewable generation and the retirement of baseload thermal generation plant has reduce overall demand but increase the need for flexibility.

The indigenous gas gap

The supply of indigenous gas has, since at least 2018, been insufficient to meet the full potential of market demand. The shortage is one of physical gas system deliverability which has left the market's midstream carriage (transmission) and containment (storage) infrastructure with insufficient commodity (gas) to operate with greater flexibility and at higher utilisation.

The progressive erosion of supply has required a demand-side response of increasing depth and breadth. By some distance the single-largest provider of demand response over this time has been Methanex. Electricity generators have also been required to accept reductions to their volumes of contracted and expected supply. Some large industrial users with contracted gas have also experienced supply curtailments while others that were nearing the end of their existing contract terms have found gas suppliers unable to offer new volumes to them.

To understand the volumes of commodity and flexibility (including storage) that are likely to be required to provide gas users with supply security we have analysed the market's four demand segments: petrochemicals, generation, large industrial and smaller industrial, commercial and residential (IC&R) load.

The petrochemicals segment, dominated by Methanex, is unique both for its scale (Methanex typically accounts for 40-45% of total market demand) and that it implicitly provides demand-side response to the market during periods of over- and under-supply. On average Methanex has a lower ability to pay than other users and its ability to absorb higher-priced gas is limited to only brief periods and/or small amounts to either cover for short term upstream outages or to allow for efficiency gains. We therefore do not explicitly account for Methanex in our needs analysis.

The thermal generation segment has an increasing need for flexibility and storage to manage systemic uncertainties that include hydrology, increasing renewables penetration, continuity of the Tiwai aluminium smelter, plant performance and fuel availability. The compound of these uncertainties mean that that by 2032 the call on gas for power generation could vary by as much as 15 PJ pa between wet and dry hydrological cycles. Compounding this is that, due to the intermittency of renewables, gas demand varies significantly over the course of a year. Thermal generation demand is likely to be volatile and could feasibly require around 250 TJ of flexibility (or 'flex') per day including Contact Energy's TCC plant or 175 TJ/day if as Contact has signalled TCC is decommissioned in 2024.

The load shapes of the major industrials and IC&R segments tend to be complementary in balancing each other's gas swings. The flexibility required by these users is around 50-60 TJ per day (TJ/day) in each direction (injection and offtake) meaning a total gap between maximum and minimum demand of around 100-120 TJ/day. To support the meeting of demand through the year we estimate a notional need of 4-5 PJ of gas storage.

In aggregate, we estimate 17 PJ of additional storage and up to 170 TJ/day of additional flexibility as required beyond that currently available in the market. This increases to 25 PJ if the recent downgrade to the storage capacity of the Ahuroa gas storage facility is taken into account.

Managing outlook uncertainty

Investors that may be looking to commit capital to bring new indigenous gas production and gas storage to market face a number of significant uncertainties. One is the time horizon over which gas storage may be needed as NZ transitions towards renewable energy. Another is the potential development of the Lake Onslow pumped hydro scheme which, if developed, would eliminate the need for additional deep gas storage. Even if further gas storage is developed, thermal generators would be required to commit significant amounts of working capital for an indefinite period 'just in case' of unfavourable supply sequences. In theory, this could tie up 10-20 PJ of gas for up to five years, representing a sizeable commitment of capital of perhaps as much as $200m.

Also, a risk is that NZ's domestic gas production is concentrated to a relatively small number of producing fields to the extent that the largest six fields contribute more than 80% of overall maximum system capacity. Current and planned drilling campaigns are largely infill of existing fields and therefore not expected to further diversify the existing production base. Events such as the Maui pipeline outage of 2011 and the Pohokura outages of 2018 demonstrated how exposed the downstream sector is to major unplanned outage events. Given the substantial financial and economic losses that are incurred by gas users and the wider economy from such events, there is a case for seeking to increase supply-side capacity and redundancy.

The uncertainties inherent within the transition period suggests a need for a supply solution that is flexible, reliable, scalable and ideally temporary.

What is LNG?

At its point of origin, LNG is simply natural gas that has undergone a refrigeration process that condenses it to a liquid state. LNG is 1/600th the volume of its gaseous state and, as a liquid, is not combustible, making it ideal for bulk transportation. At its point of destination, LNG is heated to restore it to its gaseous state then injected into the local gas transmission and/or distribution networks or combusted in-situ. LNG can therefore be regarded simply as a virtual gas pipeline that serves to connect a point or points of gas production to a point or points of gas consumption. Due to its energy density, LNG can also be stored to help balance variability in dynamic gas demand, known as peak shaving.

The energy density and transportability of LNG, combined with the clean burning characteristics of natural gas, has made it a commodity of increasing demand globally, often to substitute for coal. A useful local market analogue given the electricity sector's recent reliance on imported coal to support unconstrained operation of the Huntly Rankine units is to compare a single coal shipment delivered to New Zealand to a standard international LNG cargo. A coal shipment contains around 650 TJ of Rankine fuel whereas a standard LNG shipment can contain more than 4 PJ of equivalent fuel – a six-fold difference.

As it is simply natural gas, LNG also presents 40% lower CO_2 emissions than coal at the burner tip. This means that a single LNG cargo carries with it 150,000 tonnes less CO_2e emissions than its energy-equivalent of coal for a saving of $9m per LNG cargo at current carbon prices. Plant operating efficiencies associated with using gas in place of coal to generate power are additional and range from a low of 15% (versus OCGT) to 50% (versus CCGT).

Offsetting these benefits, is that imported LNG is considerably more expensive than imported coal on a per-unit-of-energy basis, even after accounting for the much higher carbon impost of coal.

LNG trade

LNG has been produced since the 1940s and traded internationally since 1959. There are now more than 60 countries that trade LNG. Major LNG producer/exporters include Australia, Qatar and the US. Major LNG consumer/importers include Japan, South Korea, China and Europe.

The focus over most of this time has been on large-format export/import trade involving world-scale liquefaction (export) plants and regasification (import) terminals underpinned by long-term sale contracts. Greater demand for cleaner burning fuels, an increasing number of market participants and technology advances since the turn of the century have however delivered dramatic improvements to scale and economics. Smaller and more flexible liquefaction and regasification solutions are now mainstream and there is a vibrant LNG spot market with a wide range of tradeable derivatives. Production infrastructure that is now common includes floating liquefaction (FLNG), floating storage units (FSU), floating regasification units (FRU) and floating storage and regasification (FSRU) options. LNG is also seeing increasing uptake into domestic fuel pools across both stationary energy (eg peak shaving and off-grid industrial use) and mobile energy (eg land and marine fuels, particularly in high-horsepower applications such as long-haul road freight and shipping).

Compared to indigenous gas, import LNG is an expensive option on both a capex and opex basis. Compounding this has been the recent disruptions to international trade patterns brought about by COVID-19 and the Russia-Ukraine conflict which has led to a step-change increase in LNG demand and price benchmarks. While the current period of high demand and prices is likely to be transitionary, it does serve to highlight the exposure of LNG prices to international factors. This is however no different to other fuel formats that NZ already imports to meet its energy demand including petrol, diesel, aviation fuel, LPG and coal.

LNG and New Zealand

NZ does not currently have infrastructure to enable the handling of LNG. If LNG infrastructure was to be developed, it could provide substantial additional gas market capacity and flexibility to complement existing indigenous supply and, in doing so, improve security of NZ's gas and electricity supply.
We have analysed for two generic LNG concepts:

1. **Import LNG**: LNG is imported into NZ from a LNG exporter nation, such as Australia. Imported product would require receiving infrastructure to be constructed and the LNG itself would be subject to international pricing. We examine the infrastructure options that could be used to deliver the security margins defined in our needs analysis.
2. **Domestic LNG**: LNG is produced from indigenous gas and is held as stored energy for release into the market as demand conditions support doing so. This concept would require the construction of both liquefaction and regasification infrastructure.

A key distinction between the two concepts is that only Import LNG would increase total supply into the market. Domestic LNG by contrast involves 'shaping' available indigenous gas supply to better fit market demand. Another important distinction is that of investment timeframes. Whereas Import LNG would likely involve the construction of largely seaborne (ie floating) handling infrastructure, Domestic LNG would require the construction of permanent and potentially multiple land-based liquefaction and regasification installations, therefore requiring a much longer investment horizon. The lower overall cost of seaborne LNG infrastructure and the ability to potentially share the cost of shipping with other LNG importing nations could serve to significantly reduce the average cost of landed product.

Compared to Domestic LNG, Import LNG would also provide much greater optionality and flexibility. Additional gas could be imported as and when needed and the seaborne import facility itself could be permanently demobilised at relatively short notice and at a relatively low cost if and when access to imports is no longer required. Rates of feed-in are also flexible with FSRUs able to deliver energy at up to 500 TJ/day but can be throttled-back to feed-in as low as the "boil off rate" which, on a full-sized cargo, could be as little as 5 TJ/day. To put this in perspective, the maximum feed-in rate would be more than sufficient, transmission permitting, to contemporaneously fuel all 2 GW of current thermal generating capacity. The minimum boil-off rate would be broadly comparable in scale to the current demand of NZ Steel's Glenbrook site.

Whether Import LNG or Domestic LNG, LNG could support the transition and decarbonisation of other fuel pool varietals as an alternative to diesel or coal for site-specific applications, such as power generation and industrial heat processes, and for road and marine transport applications.

Import LNG would if adopted introduce a price cap into the domestic gas market by serving as a user's fallback option. Should an LNG import option become available, indigenous gas production would, as it already does, continue to meet as much market demand as possible. Should indigenous gas production exceed demand, as may occur given current the extent of investment now being directed into the domestic sector, any requirement for LNG imports may only be brief. Other countries in similar situations have however opted to retain the security and optionality that LNG import infrastructure provides.

Given the infrastructure flexibility that it provides and a more positive long-term outlook for the supply of indigenous gas, LNG import would be consistent with current government policy of targeting 100% renewable electricity generation by 2030 while also providing improved security of gas supply across the transition period.

NZ import LNG concepts

We have considered four potential sites where receiving infrastructure for LNG cargoes could be located. All four involve the integration of floating receiving units with existing gas infrastructure. The technical concepts could involve either a FSRU or a FSU+FRU setup, with the choice ultimately a function of detailed design to best fit with the host location and setting.

An important aspect when considering the merit of each option is the extent of potential integration with existing system infrastructure, in particular the existing gas transmission network. Import facilities could support the development of options to integrate LNG into the domestic fuel pool into both on-grid and off-grid stationary (eg peak shaving and onsite fuel storage) and mobile (eg land and maritime fuel) applications.

The three sites and their potential development concepts are (in alphabetical order):

1. **Marsden Point**: A FSRU or FSU+FRU moored permanently to the existing jetty would receive LNG transferred from a shuttle carrier via conventional ship-to-ship transfer with the carrier and FSU or FSRU alongside each other. The sheltered conditions of the waterway would reduce the risk of discharge delays and the location, being north of Auckland, could serve to reduce the impact of major system outages elsewhere, such as what occurred with the 2011 rupture of the Maui pipeline. LNG operations appear also likely be able to be carried out under existing resource consents which could significantly reduce construction lead time. A major drawback however is very low (20 TJ/day) existing transmission capacity in the Northern pipeline system although this could be increased to 30 TJ/day with additional compression. The gas feed-in rate would likely therefore be a continuous (baseload) profile instead of being able to flex with peak demand and prices which

would significantly weaken the investment case for receiving LNG into Marsden Point. A debottlenecking option could be to add trucking loadout directly from the FSRU to enable the relay of LNG by road to a vaporiser and compressor installed at an injection point south of the pipeline constraint. While this would likely take longer to deliver, a fleet of 44-62 standard container-sized cryogenic trailer units could, through multiple truck movements, ship up to 145 TJ/day of gas flex directly into the transmission system atop the 20-30 TJ/day of pipeline export from Marsden Point. Any remaining flex required by the gas market could be provided by Ahuroa UGS. The road channel would be fully scalable and could also open other LNG deployment options such as peak shaving and transport fuel. Alternatively, given it is power generators that require the greatest load profile flexibility, gas-fired generation could be sited next to the LNG import concept at Marsden Point. We understand there is sufficient connection capacity at Bream Bay, where small 10 MW peakers already operate. The concept would also support upper North Island security of electricity supply by providing Auckland with fast start peaking generation from the north.

2. **Maui-A**: LNG would be transferred at sea, via ship-to-ship transfer, from a shuttle carrier to a FSRU connected to a single-point mooring system. The FSRU would connect, via the mooring system, to the Maui-A wellhead platform and the existing 35km undersea pipeline through which regasified LNG could be exported into the existing high-pressure gas network. This option has the advantage of using existing infrastructure that is underutilised. The main drawback of this option is the local sea state which would require a bespoke mooring system and potential difficulties with undertaking ship-to-ship cargo transfers. However, given the distance of the site from shore and existing oil and gas activities in the immediate area, consenting processes could be less complicated.

3. **Port Taranaki**: LNG could be received through Port Taranaki which is nearby to existing high-capacity gas infrastructure. The Port's existing jetties are currently unsuitable for accommodating both a FSRU and shuttle carrier alongside each other for cargo unloading without disrupting other port operations and without those other port operations presenting a hazard to the FSRU more generally. A potential solution could see LNG transfer undertaken at sea, either within or outside the breakwater, depending on technical and economic viabilities and profiles. Regardless, significant investment would be required to undertake necessary modifications to the port, with the preferred outcome being the construction of additional jetty infrastructure and an increase to the port's draft to be able to accommodate the FSRU and discharging carrier vessel. The securing of resource consents to support such a development is a key execution risk. In addition, the port has potential to become the shore base for offshore wind developments and it may in future prove difficult to accommodate both FSRU and wind turbine assembly operations. However, if developments occur in sequence operations at the port could probably accommodate, and indeed symbolise, the energy transition.

4. **South Taranaki Bight** – LNG could be received through a fixed-point mooring system installed at a site in the South Taranaki Bight connected via a new subsea pipeline to shore that connects with the existing Southern section of the existing high pressure gas transmission network. The attraction of the site is that it is sheltered from most swell directions apart from those from the W-NW. This would likely support a fixed spread mooring system which is considerably less expensive than the single-point system that would likely be required at Maui-A to be able handle the sea state at that site. A drawback is that the onshore high pressure network can only accommodate up to 200 TJ/day of feed-in depending on where it connects.

Implementation lead times would depend principally on approval timings, consenting and FSRU availability. The Maui-A, Port Taranaki, and South Taranaki Bight options would probably involve materially longer lead-times due to the likely need to design and build a bespoke mooring system (in the case of Maui-A and South Taranaki Bight) and dredging and port modifications (in the case of Port Taranaki). The fast-tracking of consenting processes could significantly reduce completion risk lead times.

Option appraisal

Of the options we have identified, we view the Marsden Point, Port Taranaki and South Taranaki Bight options as presenting the strongest initial potential, but for quite different reasons.

Marsden Point presents as a 'fastest fit' option that would provide the most rapid addition of deliverability to the system, with at least 20 TJ/day of import capacity potentially available within 12 months of a commitment decision. A key enabler is that Refining NZ already holds resource consents that appear to be sufficient to cover LNG import and handling operations. To meet full demand however the Marsden Point option would rely on the trucking of LNG to bypass the pipeline transmission constraint. While both cumbersome and intensive, the moving of fuel product by road is already a core aspect of the domestic fuel supply chain for crude oil, refined oil, LPG and coal. The most relevant comparison is against coal transported to the Huntly power station. Because of its low energy density, a single truck movement of coal relayed from Ports of Auckland to the Huntly coal stockpile carries 650 GJ of fuel. A single truckload of LNG potentially carried from Marsden Point for injection into the Henderson compressor station could carry double this fuel payload.

Put another way, a single coal import shipment delivered to Ports of Auckland requires 2,000 truck journeys between the Auckland CBD and the Huntly coal stockpile. Delivery of the equivalent energy as LNG would require only half as many journeys, from Marsden Point to the northern outskirts of Auckland.

A potentially promising alternative to flexible truck load-out would be to move the variability in demand to Marsden Point itself in the form of gas-fired peaking generation via a floating gas-fired power plant, or 'powership'. As well as reducing the pipeline bottleneck, the addition of fast start firming generation into the upper North Island could support electricity security margins, particularly given the extensive increments of intermittent solar and wind generation planned for the Northland region.

Three notable aspects of the powership option are that (1) it is not reliant on LNG and could operate on indigenous gas; (2) it is not an option that is specific to Marsden Point and could feasibly be sited at any location that is convenient to gas and electricity networks; and (3) being ship-mounted it would also bring the flexibility of being consistent with the 100% renewable electricity by 2030 policy target. A further potential attraction is the option to integrate a powership with a grid-scale battery, either floating on onshore.

Port Taranaki presents as a 'simple fit' option in that it offers the strongest integration with existing gas infrastructure. The biggest uncertainty regarding lead times would be consenting processes to support LNG handling at the port. If consenting was to be streamlined, a lead time of 18-24 months post-committal would be achievable. An added benefit is that investment in port modifications could benefit the port and the region beyond the duration of an LNG import operation and towards supporting the likely eventual development of offshore wind farms.

South Taranaki Bight presents as a potential 'cleanest fit' option in the way that it enables a less technical offshore receiving solution than the Maui-A option to enable interconnection to link with existing infrastructure. Relatively few modifications would be required to the FSRU or onshore area where the subsea pipeline connects to the high pressure network with little to no disruption of any existing operations or industries in the area.

Option costings

Our estimates suggest a likely development cost range of $250-338m for Marsden Point, $140-210m for Port Taranaki, $328-511m for South Taranaki Bight and $426-$624m for Maui-A.

The supply security that LNG could potentially add to the wider energy sector could support a fee model under which users pay a fixed price call option to cover infrastructure costs and a variable strike price to apply to acquired LNG and any variable costs of using the LNG import facilities.

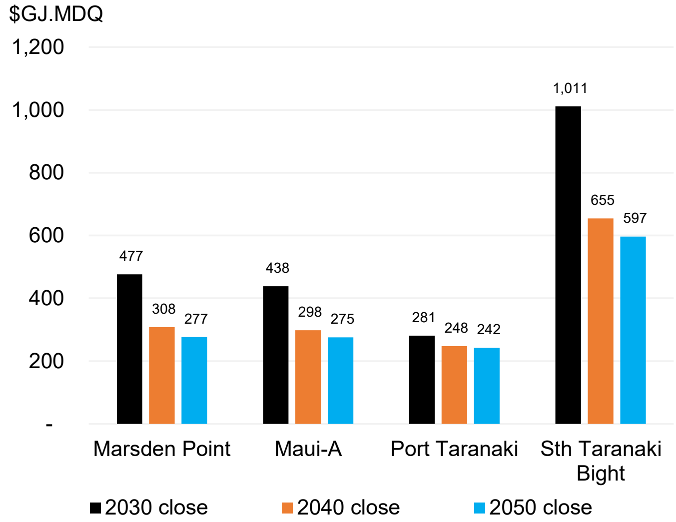
The cost of the call option would fund the fixed costs and a return on capital for the owner and for users it effectively represents a premium for the option of being able to import gas at their discretion.

Our estimates suggest the annual cost of the call option in a best case scenario and comparing between project timelines to 2030 up to 2050, would range between $48-83m pa for Marsden Point, $121-141m for Port Taranaki, $138-219m for Maui-A, and $90-152m for South Taranaki Bight. Notable is that there is potential to recover between $7-26m pa at Port Taranaki and Marsden Point by sub-leasing the FSRU into the international carrier market during the NZ summer. Sub-chartering might also be possible for a South Taranaki Bight option but is likely to be more complex to achieve as connecting and disconnecting to fixed spread mooring infrastructure could require other specialist vessel support.

As the option cost effectively serves to buy users access to gas storage and flexibility, the cost can be compared to the alternative storage and flexibility options on a capacity reservation fee (CRF) basis. The most relevant such comparison is to the Ahuroa underground gas storage (UGS) facility which we estimate presents a cost of between $400-$500 per GJ of maximum deliverable quantity (GJ.MDQ). By comparison, the relative CRF of the LNG import options investigated could be as low as $242-$281/GJ.MDQ for Port Taranaki (MDQ of 500 TJ/day), $275-$438/GJ.MDQ at Maui-A (MDQ of 500 TJ/day), $277-$477/GJ.MDQ (MDQ of 175 TJ/day) at Marsden Point and as high as $597-$1,011/GJ.MDQ for South Taranaki Bight (MDQ of 150 TJ/day).

The strike price of the gas itself would be determined by international markets. Based on historic pre-Ukraine and pre-COVID trends of the spot market around the Asia Pacific region and the ability for NZ buyers to preferentially source cargoes during the northern hemisphere summer, this would likely range between $9.60/GJ and $11.80/GJ.

LNG import option cost estimates (best case)



Source: Enerlytica

We note however that global LNG prices have recently been much higher than this range due to the impact of COVID supply chain disruptions, fuel switching and very strong Northern Hemisphere demand as Europe manages the political impact of the Ukraine conflict on its energy supply. The disruption has also seen the usual summer-winter price disparities disrupted by European buyer strategies to maintain high gas storage levels.

Additional to the cost of LNG would be the variable cost of using the facility which could be as high as $3.0-$4.7/GJ for Marsden Point and as low as $1.6-$3.4/GJ for the South Taranaki Bight and Port Taranaki options. Maui-A lies in between with a range of $1.7-$3.7/GJ. Excluding the fixed option cost, the variable cost of delivered LNG delivered would therefore potentially lie between $44.3/GJ and $63.9/GJ based on post-Ukraine LNG prices and between $11.2-16.5/GJ on historic pre-Ukraine prices.

NZ market integration

In respect of likely NZ market impacts:

- LNG-backed gas would stand in the market as marginal gas at or near the bottom of the merit order and by doing so serve to provide users with a floating ceiling price proxy.
- The LNG-backed commodity price would include an embedded value for flexibility whereas existing commodity-only price benchmarks for indigenous gas do not.
- LNG would provide supply certainty and flexibility during periods of constrained indigenous gas availability, including cover for major scheduled and unscheduled asset outages.

Import LNG could integrate with existing and/or new UGS facilities to provide further optionality for in-country storage to receive imported gas. For example, a LNG import facility at Marsden Point could overcome the low pipeline capacity by feeding gas to deposit into UGS over time and allow the majority of flexibility to be delivered in that way. Access to local UGS would however represent an additional supply chain cost and it would likely be less expensive for users to manage flexibility through the FSRU given that the fixed costs of the facility would already be paid for via the fixed option cost.

Import LNG would also bring the benefit of fuel certainty, whereas the storage of indigenous gas requires there to be sufficient indigenous gas market liquidity available to cycle into and out of storage to meet demand. We therefore think import LNG could be considered alongside, rather than instead of, standalone options to add permanent in-country gas storage.

Domestic storage expansion options

We have also considered options to increase system storage capacity for indigenous gas beyond those options that are already available in the market, being the Ahuroa UGS, field-specific standby gas capacity, line pack, LPG blending, demand-side response and contractual swaps. The expansion options we considered can be divided into below-ground and above-ground formats.

Below-ground storage options

Below-ground options refer to potential expansion opportunities that involve the development and/or management of sub-surface infrastructure. Specific options we considered were:

1. **Underground gas storage**: There are at least two known UGS options:
   - **Expansion**: Increase the cycling capacity of the Ahuroa UGS facility from 65 TJ/day. Due to the recent decline in performance of the Ahuroa UGS facility we have opted not to evaluate this as an expansion option. Indeed, the decline could have the effect of increasing the need for further storage capacity.
   - **Conversion**: Development of new UGS capacity, probably via the conversion of the depleted Tariki field, to meet the buy-side interest expressed by Genesis Energy for up to 55 TJ/day of cycling and 20 PJ of storage.
2. **Indigenous standby gas capacity:** Unused supply-side flex capacity that either does or potentially could exist in producing fields and which could be called upon during times of short supply.

The ultimate cost of adding UGS capacity at Tariki would depend on development costs and in particular the requirements for new wells. Our analysis indicates a CRF for the Tariki option of $104-215/GJ.MDQ depending on payback horizon.

In respect of indigenous standby gas capacity, it appears that existing fields may already operate at or near their rated capacities. Even with additional indigenous production expected in 2023, the additional flexibility the market is seeking may not be available due to physical and commercial constraints on dispatch.

Above-ground storage options

Above-ground options refer to expansion opportunities that involve the development and/or management of surface-based infrastructure. Specific options we considered are:

1. **Domestic LNG**: A closed NZ loop of both liquefaction and regasification infrastructure to enable the controlled storage and carriage of indigenous gas.
2. **CNG**: Compression of indigenous gas to enable larger-scale storage and carriage.

3. **LPG**: Blending propane and butane into the reticulated gas stream while remaining within the specification standard for natural gas supply.
4. **Methanol**: Similar to domestic LNG, but using existing gas-to-methanol as a means of 'storing' natural gas and converting power generation facilities so they can use methanol as fuel

Of these options, we view CNG, LPG, and methanol as having more potential than Domestic LNG. Despite this, the low relative materiality offered by CNG and LPG against the storage and flex gas gaps we have defined is in each case a major drawback.

CNG could be viable as a niche, site-specific, multi-day peak shaving solution if the swing required is less than 1-3 TJ and the time period it is needed for is only a couple of days. We do not however view it as viable towards filling the requirement for large-scale grid-connected storage.

Indigenous LPG is, in some cases, already left in natural gas streams to increase gas bulk to support portfolio management. Capacity constraints (LPG blending does not provide material additional gas volumes), infrastructure access (the LPG supply chain is tight, making it logistically difficult to throttle volumes), opportunity costs (LPG is itself a valuable sales product which requires a high gas netback value to justify repurposing it as gas), gas quality limitations (the ability to blend higher volumes of Kupe LPG into the gas stream is low due to the impact on gas richness) and institutional ownership complexities compound to discount the viability of LPG blending to contribute towards providing additional system storage capacity. LPG does however have potential to be applied as fuel for peaking electricity generation using underutilised handling and storage facilities already in operation in South Auckland.

Methanol offers significant potential in terms of scale and ease of execution. Methanex already produces large volumes of methanol from gas, more than 95% of which is exported. Importantly, there are already several large methanol storage tanks operating in the Taranaki region, some of which are underutilised. The conversion of existing thermal power plant to be able to accept methanol would be relatively straightforward and low cost.

Option appraisal

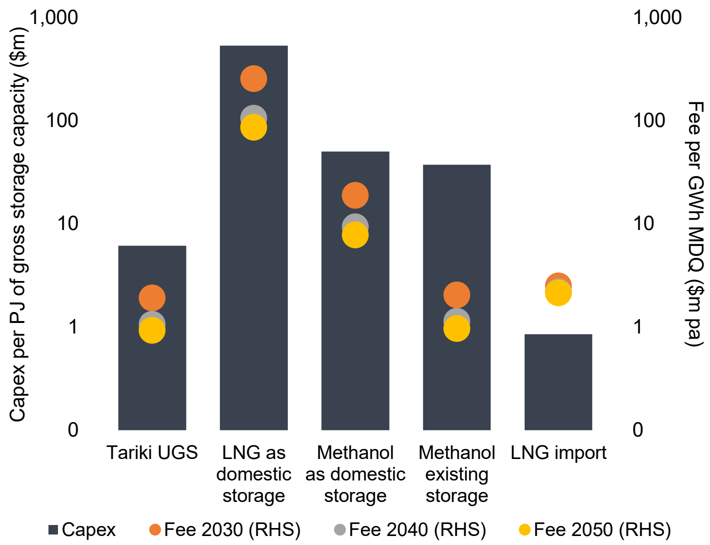
A shared drawback of any domestic storage option, with the minor exception of LPG which does have limited import optionality, is a reliance on domestic fuel availability to charge and draw-down storage as it is needed. Adding storage capacity for indigenous fuel does not on its own increase the size of the fuel pool; it simply increases tankage volume which, without gas to cycle through it, could serve little purpose. If sufficient indigenous gas does become available to enable unconstrained cycling, as recent reserve disclosures from field operators suggest is likely to occur, then UGS options present as the most cost-effective solution.

Within this frame, Tariki UGS presents as the most attractive option as it adds significant additional storage capacity into the market. The domestic fuel pool could also be expanded by increasing the uptake of methanol, probably into powergen applications.

A shared challenge with any gas storage investment case is the term against which a buyer of storage capacity would commit. For UGS options we expect that an investor would require a commitment term of at least 15 years, which with construction lead times would extend well beyond the government's 2030 target to achieve 100% renewable generation. Also a major consideration when assessing the case for further investment in domestic energy storage of any format are the potential market implications of the proposed Lake Onslow pumped hydro scheme. In our view, these policies are already serving to deter potential investors from progressing viable deep energy storage options that could serve to improve NZ's security of supply while reducing emissions.

To that end, a specific opportunity that we consider as justifying further investigation is that of floating and/or temporary land-based power generation to support security of electricity supply in the upper North Island across the transition period out to and if need be beyond 2030. There are potentially multiple locations that would be suitable for such plant and also multiple fuel options suitable for that plant including indigenous gas, methanol and LPG.

Benchmarking of indigenous deep energy storage option cost estimates, log scales



Source: Enerlytica

1. THE NEW ZEALAND GAS SECTOR

PURPOSE

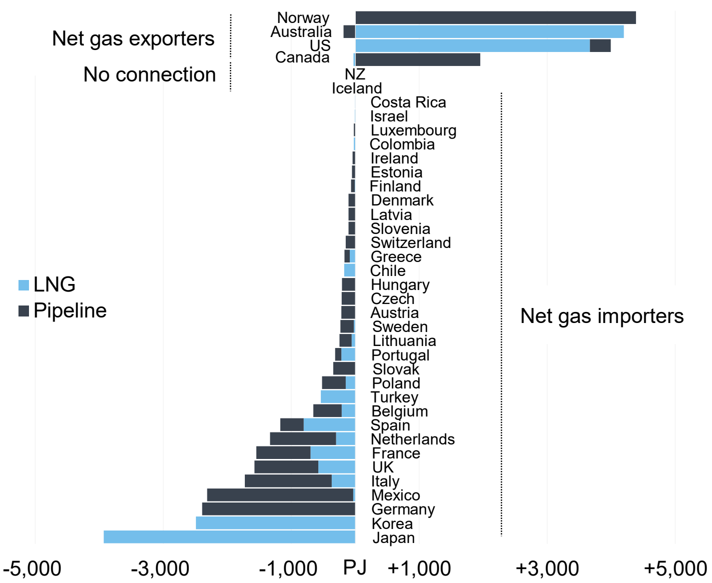
The purpose of this section is to identify and analyse those key aspects of the NZ gas sector relevant to the issues of availability, capacity and flexibility.

1.1 Market setting

The NZ gas sector is located entirely in the North Island. It has no existing connection to the gas supply networks of any other country, either by way of import/export pipeline or LNG liquefaction or regasification infrastructure. This makes the NZ gas market unique among OECD nations (Figure 1). Under current infrastructure and arrangements therefore, local market gas supply must always match local market gas demand.

On the supply-side, all producing fields are located in the Taranaki region. The first 30 years of NZ gas market development, from 1970 through to the early 2000s, were defined by the physical and commercial dominance of the Maui and Kapuni fields. Since the early 2000s the supply-side of the sector has broadened significantly such that market demand is now met by supply from a larger number of smaller producing fields. More recently, over the past 3-5 years, the trend has been of each major producing field entering production decline.

Figure 1: OECD nation gas trade, 2021



Note: Iceland does not have a gas market of any significance

Source: BP Statistical Review of World Energy data, Enerlytica

On the demand-side, the overall size of the market has broadly reflected the aggregate level of gas demand from a small number of comparatively large petrochemical producers and electricity generators which together typically account for more than three-quarters of total demand. Industrial, commercial and residential load makes up the balance.

The sector is serviced by a mature and integrated network of pipeline and related midstream infrastructure, facilities and services. This includes an underground gas storage (UGS) facility at Ahuroa built in the late 2000s to provide seasonal flexibility for electricity generation.

Demand

The demand-side of the NZ gas market has two generic constituents (Figure 2):

1. **Energy conversion:** Gas applied as a feedstock that is reformed for petrochemical manufacture and electricity generation. Methanol producer Methanex accounts for the majority of energy conversion demand. Historically, more than 80% of total gas market volume has been consumed by energy conversion applications. Since 2000, demand from the petrochemicals and non-energy segment has shown significant volatility, ranging from a high of 100 PJ in 2000 to a low of 23 PJ in 2005. Petrochemical and non-energy demand in 2022 was 59 PJ.

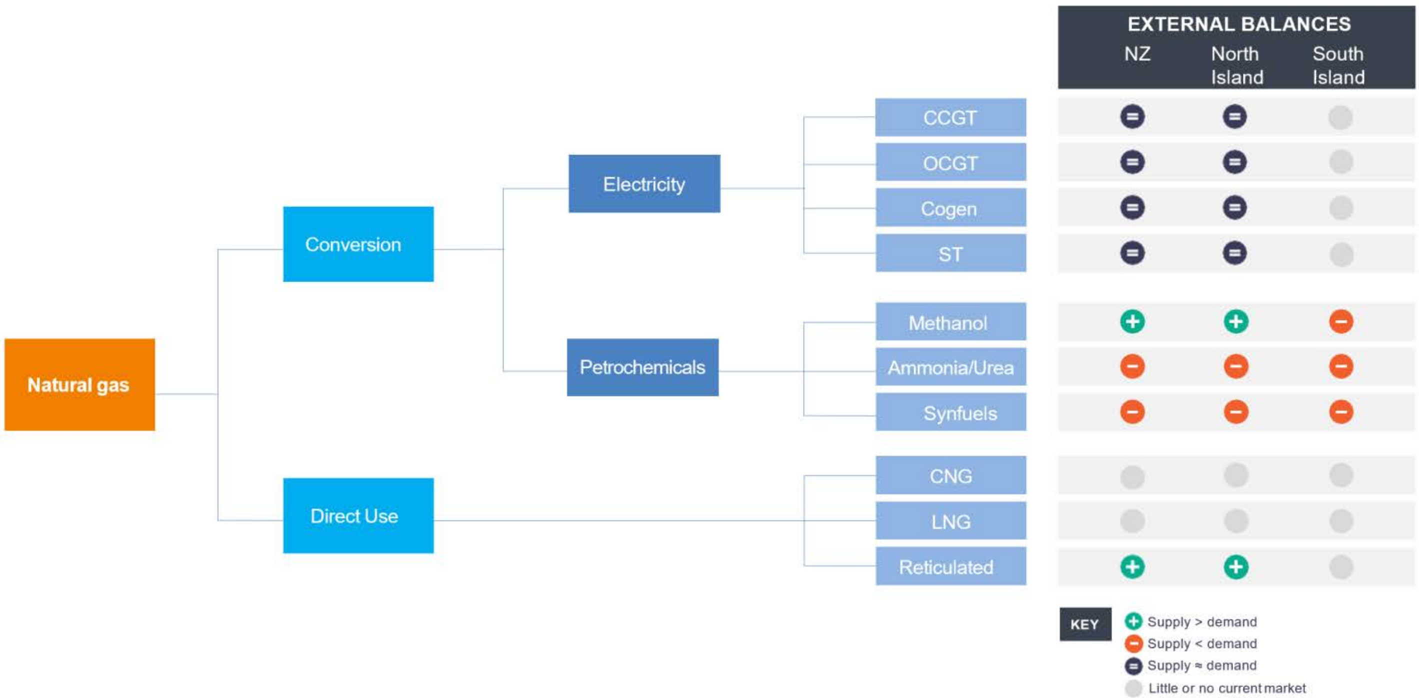
2. **Direct use:** Gas used directly for mostly heat-led applications into industrial and commercial (I&C) (~30 PJ pa) and residential (~7 PJ pa) demand channels.

Methanol

Methanex is by far the largest gas user in the market. The three methanol plants that it operates (two at Motunui with 850 ktpa capacity apiece and one at Waitara Valley with 530 ktpa capacity) can, when operating at their combined capacities, require 85-90 PJ pa of gas depending on gas composition.

Methanex's gas draw comprises a mix of feedstock gas and for onsite process heat. Of this, feedstock gas accounts for around two-thirds of its total gas demand.

Figure 2: NZ gas applications vs NZ self sufficiency



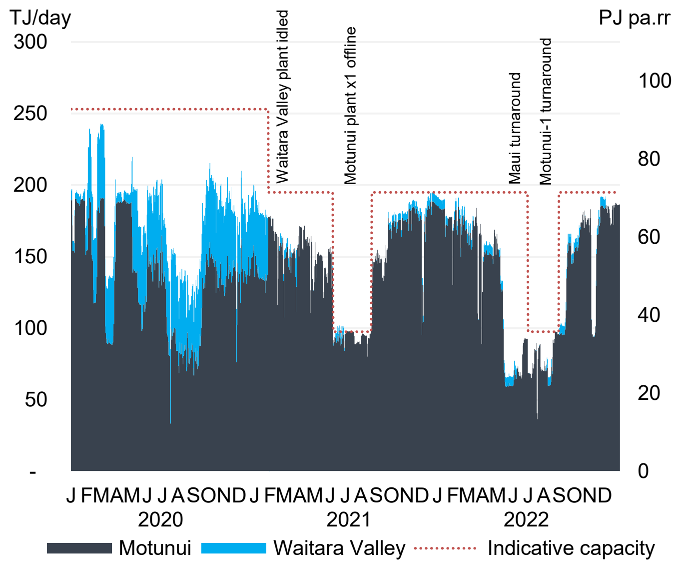
Source: Enerlytica

To meet its substantial gas needs, Methanex is known to operate a gas gathering strategy that sees it procure gas from a number of suppliers under a range of commercial structures and terms. The largest of these are long-term gas supply agreements (GSAs) with OMV and Todd Energy for the supply of Pohokura and Mangahewa gas respectively. Methanex is also thought to have been a buyer of significant volumes of Maui gas and resold gas from wholesale gas market buyers with long-gas positions. Genesis is one such wholesale gas reseller from which Methanex is known to have purchased gas during the 2010-20 period.

Methanex is unique in the market in that it is willing to take on significant reserves and deliverability risk to secure firm supply. In exchange it receives a lower gas price. It has a long history of throttling capacity utilisation to meet gas market conditions. This includes decisions not to refurbish plant on the lapsing of certification. A sharp deterioration in gas availability during the mid-2000s saw Methanex idle both its Motunui plants. As gas availability subsequently improved, between 2008 and 2013 Methanex progressively re-started all idled capacity. Between 2013 and 2020 when all three of its plants were operating, Methanex accounted for up to 46% of total gas market demand.

Gas shortages related to the accelerated decline of the Pohokura field saw Methanex decide in December 2020 not to proceed with a scheduled 1Q 2021 turnaround of its Waitara Valley methanol plant (Figure 3). The turnaround would have certified a further 4-5 years of operation however the plant was instead withdrawn from service and is now described publicly by Methanex as "*idled indefinitely due to insufficient natural gas availability*".

Figure 3: Methanex daily gas deliveries, 2020-2022



Source: OATIS, Enerlytica

Ammonia-urea

Ballance Agri-Nutrients owns and operates NZ's only ammonia/urea plant (AUP) at a site adjacent to Todd Energy's Kapuni Gas Treatment Plant (KGTP). For its process Ballance draws a gas load of ~7 PJ pa. It also requires a small quantity of high CO_2 gas which it sources directly from KGTP.

Electricity generation

Thermal electricity generation is supplied via a 2.4 GW portfolio of grid-connected formats spanning CCGT, OCGT, cogen and conventional steam turbine formats (Table 1). Generation gas demand has fallen from a peak 109 PJ in 2001 to a low of 42 PJ in 2022. The contributors to this fall include:

- Construction of new geothermal capacity which has squeezed high-capacity gas-fired generation from the electricity merit order. This contributed directly to the decommissioning in 2015 of two large gas-fired power stations (400 MW Otahuhu-B CCGT and 120 MW Southdown cogen).
- Replacement of gas with substitute thermal fuels where feasible, in particular the displacement of gas use with coal at the Huntly power station.
- Construction of underground gas storage facilities, thereby increasing fuel portfolio flexibility and reducing the need for instantaneous gas purchase.
- Weak post-GFC underlying electricity market demand growth.
- Government policy direction including an explicit target of 100% renewable generation by 2030, a ban on new offshore gas exploration, a ban on new baseload thermal generation and promotion of the Lake Onslow pumped hydro scheme.

Table 1: >10 MW Grid-connected thermal generation plant

Unit	Operator	Format	First prdn Year	Cap. MW	Thermal efficiency %
Huntly Rankines	Genesis	ST	1982-85	750	33.0%
Huntly CCGT	Genesis	CCGT	2007	385	48.6%
Huntly OCGT	Genesis	OCGT	2004	48	34.2%
SPS CCGT	Contact	CCGT	1998	377	48.6%
SPS OCGTs	Contact	OCGT	2010	210	40.4%
Te Rapa	Contact	Cogen	1999	44	30.8%
Whirinaki	Contact	OCGT	2004	155	33.0%
McKee	Nova	OCGT	2013	100	34.0%
Junction Rd	Nova	OCGT	2020	100	34.0%
Edgecumbe	Nova	Cogen	1996	10	31.3%
Whareroa	Nova	Cogen	1996	68	38.7%
Kapuni	Nova	Cogen	1998	25	38.7%
Glenbrook	Alinta	Cogen	1997	112	n.a.
Kinleith	Oji	Biocogen	1998	40	32.7%
Total				**2,424**	

Notes:
Contact Energy will close the Te Rapa cogen plant in mid-2023 and TCC in late 2024
The Whareroa cogen operates as JV between Nova Energy and Fonterra
Whirinaki has operated on diesel since commissioning but can operate on gas

Source: MBIE data, EA data, Enerlytica

Table 2: Vertical integration of thermal generators

Company	Upstream	Midstream	Downstream
Contact Energy	Buyer entitlements to Maui and Pohokura gas	AGS capacity and storage entitlements	631 MW capacity plus gas wholesale and retail businesses
Genesis Energy	Equity gas entitlements to Kupe gas. Buyer entitlements also to Pohokura gas	Huntly coal stockpile	1,183 MW capacity plus gas wholesale and retail businesses
Nova Energy	Via parent Todd Energy, equity gas entitlements to Mangahewa, McKee and Pohokura gas	AGS capacity and storage entitlements, reinjection access at McKee	293 MW capacity plus gas wholesale and retail businesses

Source: Enerlytica

To manage their generation portfolios, each of the three major generators operate differing extents of vertical integration within their wider businesses. That integration comprises a mix of equity (ie ownership) and commercial (ie contractual) arrangements in the upstream, midstream and downstream sub-sectors to enable each business to manage asset availability and fuel requirements. The major aspects of integration for each of the major thermal generators are summarised in Table 2. A detailed account of each company's gas business is presented in Table 3.

Industrial & commercial

I&C demand accounts for ~30 PJ pa of load across a range of individual sites primarily spanning the manufacturing and food processing sectors. The largest tranches of single-site industrial demand are Oji Fibre Solutions (~3.0 PJ pa) and NZ Steel (~2.5 PJ pa). Fonterra operates nine North Island dairy factories that draw natural gas and which together account for load of ~4.5 PJ pa excluding gas used at cogeneration sites.

Load profiles vary by individual user and reflect factors such as competing fuels (eg NZ Steel has some ability to take either or both of process and/or natural gas) and seasonality (eg the peak dairy season runs from August-May). Scheduled and unscheduled outages also impact load profiles.

Residential

Mass market gas demand of ~7 PJ pa comprises supply to nearly 300,000 customers. The shape of this load has a strong winter bias reflecting peak heating demand.

Table 3: Gas businesses of major thermal generators

Generator	Plant		Fuel profile
Genesis Energy	Huntly CCGT Huntly OCGT Huntly Rankines	385 MW 48 MW 750 MW **1,183 MW**	**Gas business**: With 1,183 MW of installed capacity Genesis is the electricity market's largest thermal generator and is also the country's largest energy retailer including 109,000 gas customers across its Genesis Energy and Frank Energy brands. Its book makes it the gas market's second-largest buyer, behind only Methanex. **Entitlements**: Genesis's gas book is underpinned by entitlements associated with its 46% equity interest in the Kupe JV, over which it holds contractual rights to all Kupe gas for the life of the field. Genesis is also a known buyer of a 4 PJ pa tranche of Pohokura gas for delivery that commenced 1 January 2021 and will extend to the end of 2024. This Pohokura tranche partly replaces an existing but much larger tranche of contracted Pohokura gas under a GSA that lapsed on 31 December 2020. **Flexibility**: Genesis's main source of seasonal fuel flexibility has historically been provided by its Huntly coal stockpile to support Rankine operation. To reduce its reliance on the stockpile Genesis has said that it is seeking to secure 20 PJ of gas storage by 2025 with 55 TJ/d of injection and withdrawal capability. **Strategy**: Genesis has stated a target to not use coal to generate electricity in normal market conditions by 2025 and to phase out coal completely by 2030. To enable this, a separate programme, labelled Futuregen, aims to add 2,650 GWh pa of new renewable generation build by 2030.
Contact Energy	SPS (TCC) CCGT SPS OCGTs Te Rapa cogen	377 MW 210 MW 44 MW **631 MW**	**Gas business**: Contact has 631 MW of installed gas-only capacity and is the country's second-largest energy retailer, behind Genesis, with 70,000 own-brand customers. **Entitlements**: In 2019, Contact agreed arrangements with OMV and Methanex that provided it with preferential access to firm and contingent parcels of Maui gas in exchange for agreeing to forego legacy entitlement rights it had previously held over Maui. Contact is also known to have been a buyer of a 8 PJ pa tranche of Pohokura gas for delivery commencing 1 January 2021 through to the end of 2024. **Flexibility**: Contact holds long-term access rights to AGS for 45 TJ/day of reserved injection and extraction capacity and 13.5 PJ of working gas storage. This entitlement has however been heavily impacted by a downgrade to AGS's operating capacities. **Strategy**: In June 2022, Contact announced that it would close its Te Rapa cogen plant in June 2023. It has also said it plans to close TCC in 2024 following the commissioning of its 174 MW Tauhara geothermal power station which is currently under construction.
Nova Energy	McKee OCGTs Junction Rd OCGTs Whareroa cogen KGTP cogen	100 MW 100 MW 68 MW 25 MW **293 MW**	**Gas business:** Nova is the downstream business of Todd Energy which holds substantial upstream entitlements via its ownership interests in the Mangahewa, McKee, Pohokura and Kapuni fields. Nova is also a large supplier of wholesale gas into the I&C segment as well as supplying 35,000 own-brand retail customers. **Entitlements**: Unlike Genesis and Contact which are stock exchange listed, Nova is not obligated to disclose details of its gas portfolio to the market. Its supply will however be dominated by direct access to equity gas entitlements held via Todd Energy's 26.0% interest in the Pohokura JV and outright interests held in the Mangahewa/McKee and Kapuni fields. **Flexibility**: Nova's gas business benefits from a number of direct and indirect channels to manage flexibility. Its main direct channel is via long-term AGS access rights for 20 TJ/day of reserved injection and extraction capacity and 4.5 PJ of storage. Indirect channels include the direct ability to throttle any of its thermal generating plants to meet supply, McKee gas reinjection capacity and its Mangahewa LPG straddle plant. **Strategy**: Likely continuation of leveraging vertically integrated business model.

Note: Figures stated at 31 December 2022

Source: MBIE data, EA data, GIC data, Enerlytica

Gas supply chain and access

Meeting market demand requires the service of a long chain of gas infrastructure. User access to individual components of supply chain infrastructure varies depending on the nature of the asset and commercial access rights (Table 4).

Table 4: Gas supply chain constituents

	Service	Access basis	Major providers
Producer			
	1. Commodity	Bilateral contractual	OMV, Todd, Greymouth
	2. Storage	Bilateral contractual	Flex Gas (a First Gas company)
	3. Transmission	Open. Regulated pricing & mgmt.	First Gas
	4. Distribution	Open. Regulated pricing & mgmt.	First Gas, Vector, Powerco
Consumer			

Source: Enerlytica

Commodity

The supply of gas has both physical and financial dimensions, each of which directly impacts gas access and liquidity.

Physical supply

Gas is currently supplied from around 15 producing fields. A common characteristic across the portfolio is of asset and production maturity. The most recent fields to arrive to market, Kupe and Kowhai, entered continuous production in December 2009. Like each other producing field, including Mangahewa which while much older only reached plateau in 2019 following a major development programme that commenced in 2012, all of the largest producing fields are now off-plateau and in varying stages of production decline (Table 5 and Figure 4).

Based on the most recent statutory disclosures of field operators, the largest six fields contribute 87% of overall maximum system capacity. With this comes concentration risk, such that when one or more of these fields suffers performance decline without a compensating increase in production available from other fields then supply margins reduce. This is precisely the risk that materialised in 2018 when multiple unscheduled outages and subsequent accelerated field decline at Pohokura were not able to be offset by increases from other fields due to them also being in decline.

Table 5: Major producing field production, reserves & resources

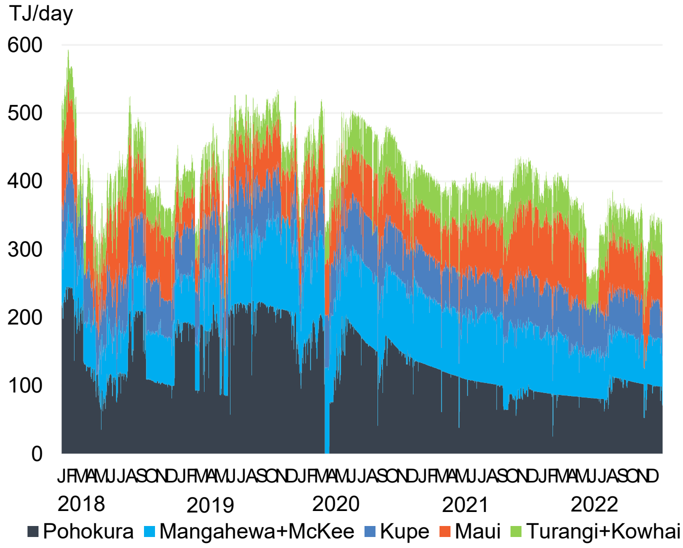
Field	First prdn	Production plateau		Production 2022		Reserves 2P	2C
	Year	Year	TJ/day	TJ/day	PJ	PJ	PJ
Pohokura	2006	2018	244	91	33	342	115
Mangahewa	2001	2019	129	73	27	430	1,188
Kupe	2009	2019	77	54	20	214	36
Maui	1979	2002	520	75	28	314	50
Turangi	2006	2020	54	47	17	452	72
Kapuni	1970	1996	60	38	14	166	814
				377	**138**	**1,917**	**2,276**

Source: MBIE data, field operators, Enerlytica

Equity ownership of gas reserves and production is dominated by OMV and Todd Energy due in large part to their respective interests in the Pohokura, Maui and Mangahewa fields (Figure 5). Smaller equity interests are held by Greymouth Petroleum and relate to the Turangi and Kowhai fields while interests of Beach Energy and Genesis reflect their respective interests in the Kupe JV.

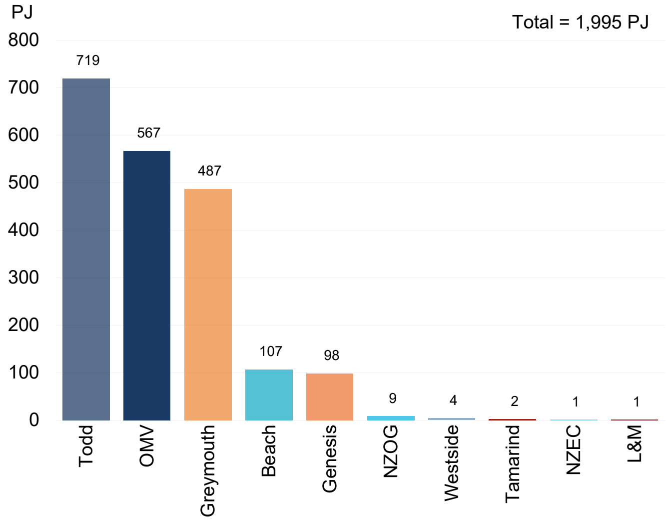
All gas processing and separation is undertaken by gas producers without any known third-party ownership or involvement. Currently there are no known examples where gas production is toll-processed for interests not directly associated with processing plant ownership.

Figure 4: Major producing field daily production, 2018-2022



Source: OATIS data, Enerlytica

Figure 5: 2P equity gas entitlements, at 1 January 2022



Source: MBIE data, Enerlytica

Commercial supply

Long-term end user access to wholesale gas is typically formalised in a bilateral GSA between a supplier (Seller) and user (Buyer). The detail of GSAs can and do vary widely, but generally involve two generic volumetric dimensions:

1. **Annual Contract Quantity (ACQ):** The volume of gas that Seller must deliver and Buyer must take in a contract year. ACQ is typically backed by a Take or Pay (ToP) commitment which agrees a minimum volume of gas that a Buyer will pay for at the contract price irrespective of physical gas delivered.
2. **Flexibility:** Intra-year flexibility can be handled in many ways in GSAs, but a common mechanism is to agree a Maximum Daily Quantity (MDQ) of gas to be delivered within any 24-hour period. In simple terms therefore, flexibility can be thought of as a Buyer's contractual ability to manage MDQ within ACQ.

Standalone to the commercial concepts of ACQ and MDQ is the physical constraint of field deliverability, being the physical ability of the field to produce the gas volumes required to meet sales commitments. Sellers are careful to manage ACQ and MDQ within field deliverability constraints, however when unexpected falls in deliverability eventuate, as has been the case with Pohokura since 2018, supply margins can come under significant pressure. The key point is that physical and commercial gas availability are two very different concepts. Commercial availability is a subset of physical availability such that when physical availability is constrained, commercial availability also reduces. For users that have entitlement under existing GSAs the result has been a reduction by Seller of ACQ volumes. For users that do not hold existing entitlements or whose existing GSA(s) are nearing expiry, the situation can become difficult as gas sellers are less likely to have excess liquidity to be able to offer beyond their existing sell-side commitments.

Gas portfolio flexibility

Typical gas supply contracts provide buyers with some flexibility to nominate up and down for gas within prescribed limits. The level of contractual flexibility available to buyers has however been falling with the decline of the Maui field since the early 2000s and more recently as other fields have exited plateau. As the availability of gas flexibility has fallen participants have turned to other options such as time swaps to procure the flex they require.

There are primarily two means of execution for time swaps (bilateral and on-market) and two pricing bases (leg volume or leg value).

Bilateral time swaps

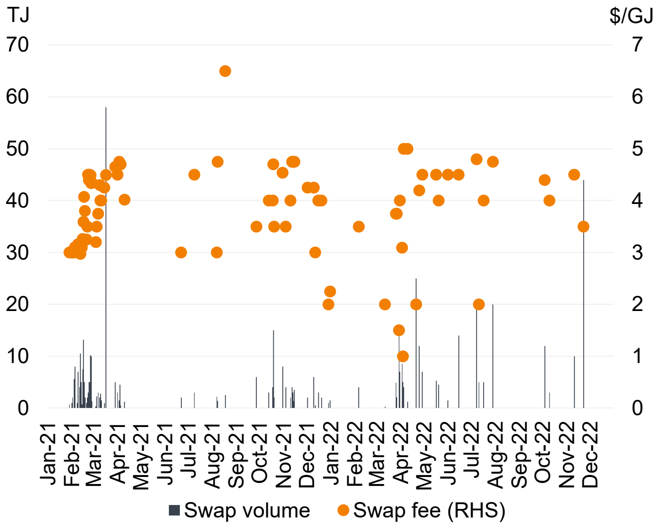
Bilateral time swaps are agreed directly between two market participants. Unlike is the case with on-market transactions where trade details are public, bilateral deals usually involve little or no public disclosure of deal specifics. Market events do however occasionally enable such deals to be identified and quantified. One such example is what appears to be a significant swap deal between Genesis and Contact relating to gas that Genesis was entitled (and required) to uplift under its Kupe buy-side GSA obligations but which due to a major scheduled outage of its Huntly CCGT across the month of April 2021 it was not able to place into its usual sales channels. Without the swap Genesis would have been likely to have directed that gas into the Rankine units where it would otherwise have served to defer coal burn into later periods. Instead, the swap served to defer gas uplift, enabling Genesis to call on the swapped gas during the peak winter period to support CCGT dispatch.

This represents a highly efficient outcome for the parties and for sector security margins. This is because of the benefit of being able to notionally 'bank' gas to enable Genesis to instead use it during periods of much higher value (typically winter months), increasing overall fuel flexibility (gas is retained for plant that cannot run on other fuel instead of directing that gas into the Rankines which can accept coal) and into plant with much higher efficiency (CCGT dispatch is nearly 50% more fuel-efficient that Rankine dispatch) and much lower emissions (on a per-kWh basis Rankine dispatch produces approximately triple the CO_2e emissions of CCGT).

On-market time swaps

On-market time swaps are executed directly via the emsTradepoint gas market platform. Users have swapped gas through the market for several years, typically as large parcels between time periods. In this sense the effect is no different to bilateral time swaps other than by making use of a standardised gas contract. Examples during 3Q 2020 saw 344 TJ swapped between 3Q 2020 and 2021 to assist users manage the unexpected drop in Pohokura deliveries. Swap fees for this period were below $1.20/GJ.

Figure 6: Short-term market time swaps, 2021-2022



Source: emsTradepoint data, Aotearoa Energy, Enerlytica

The trading of shorter-term time swaps has lifted significantly since the start of 2021 with tighter electricity market conditions driving buyers to defer their gas access from autumn to winter. This has brought with it a sharp increase in pricing, with swaps fees averaging above $4.00/GJ (Figure 6).

Storage

Existing thermal fuel storage capacity is made up of two key installations:

1. Ahuroa UGS facility
2. Huntly coal stockpile

Ahuroa UGS facility

Ahuroa is an underground gas storage facility that uses the depleted reservoir of the Ahuroa gas-condensate field to provide gas flexibility services to entitlement holders of cycling and storage capacity.

Ahuroa was developed by Contact Energy between 2008 and 2011 to provide flexibility for its Stratford Power Station (SPS). The development of Ahuroa was to enable Contact to receive gas during periods of low gas and electricity seasonal market demand (typically summer) and/or periods of oversupply and deposit that gas into storage to be withdrawn at a later time during periods of high gas and electricity demand and/or undersupply (typically winter). Its specific objective was to facilitate trading arbitrage by buying generation fuel at low off-peak prices and deploying it into the SPS OCGTs to hit high electricity spot prices and maximise electricity netbacks.

A detailed account of the development of Ahuroa including timings, costings and commercial arrangements is included in Section 4.

Huntly coal stockpile

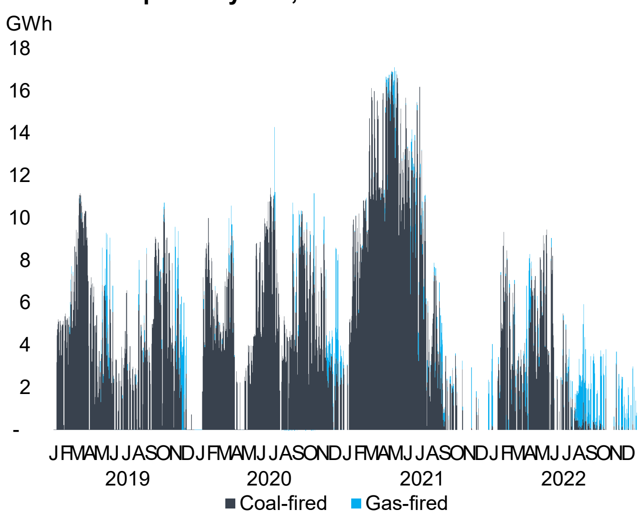
To support the unconstrained operation of its HPS Rankine units Genesis maintains an onsite coal stockpile. Since 2018, a series of dry hydro sequences and gas shortages have increased Genesis's reliance on using stored coal to meet contractual commitments it has with other generators and its own retail book (Figure 7).

Until the mid-2000s coal to Huntly was sourced entirely from the Huntly coal fields. Declining local coal availability and gas constraints during the 2005-2010 period saw Genesis turn to coal imports to supplement local supply. Imports fell during the 2010-17 period when Pohokura and then Kupe gas arrived to market but have increased sharply since 2018 as gas availability has again fallen (Figure 8).

The operating metrics of coal-rich Rankine operation are worth recording:

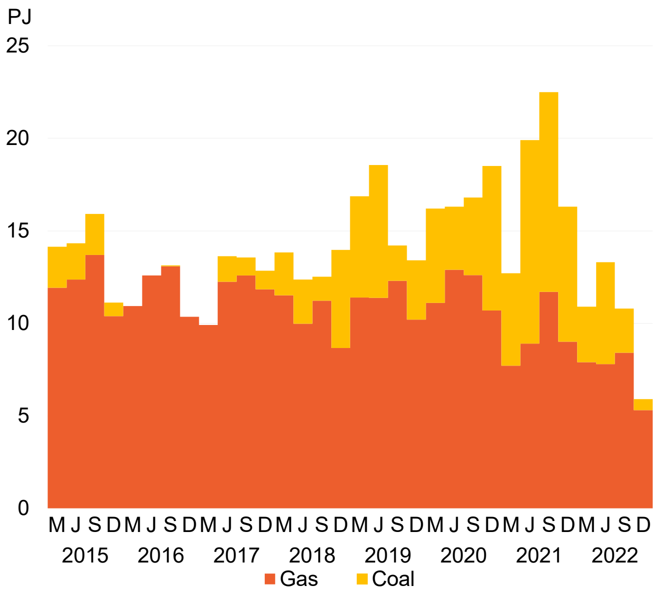
- When operating baseload, each 250 MW unit requires nearly 3,000 tonnes of coal per day as fuel. Three-unit operation therefore requires a maximum coal feed of 370 tonnes per hour, equating to more than 250 kt per month if operated on a continuous basis.
- Imports typically arrive from Indonesia on bulk carriers carrying 34 kt cargoes. A single cargo is sufficient to fuel a single 250 MW Rankine unit operating baseload for ~11 days.
- While import volumes have primarily been receive through handling facilities at Port of Tauranga, a shortage of handling capacity into and out of the port at peak times means that cargoes have often been handled through Ports of Auckland. Coal unloaded in Auckland can only be moved to Huntly by truck at around 30 tonnes per movement. Each shipment into Auckland therefore requires the equivalent of 2,000 truck journeys.

Figure 7: Huntly power station daily generation dispatch by fuel, 2019-2022



Source: emi data, Enerlytica

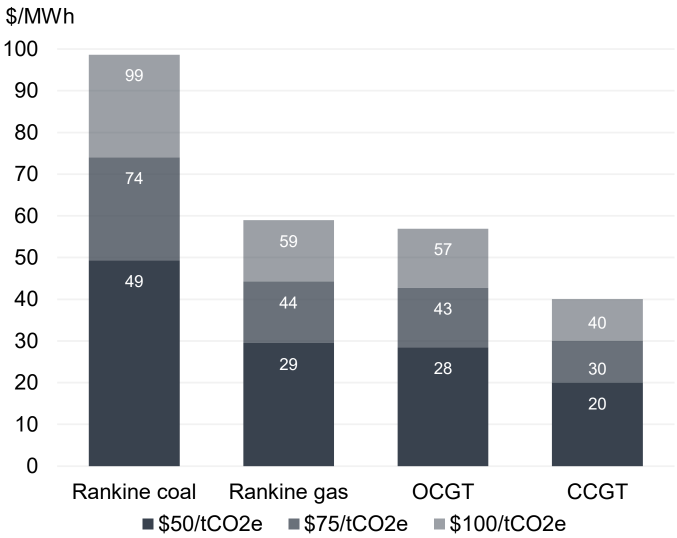
Figure 8: Genesis Energy fuel purchases, quarterly 2015-2022



Source: Genesis Energy data, Enerlytica

- Under NZ's ETS, each import cargo also delivers the equivalent of 60 kt of CO_2e, with a current market cost under the ETS of $4m.
- The Rankine units are considerably less fuel-efficient than other gas-fired alternatives. When combined with the much higher emissions profile of coal, the CO_2e component of gas-fired generation is at least 40% (in the case of gas-fired Rankine dispatch) and as much as 60% (in the case of CCGT dispatch) less expensive than coal-fired Rankine dispatch (Figure 9).

Figure 9: Thermal SRMC imposts at increasing NZU pricing



Source: MFE data, Enerlytica

Genesis Futuregen strategy

In mid-2020, Genesis issued a new strategy, branded by it as "Futuregen", that aimed to displace existing baseload thermal generation with new renewable build. The strategy sits alongside existing commitments Genesis has made to not use any coal to generate electricity in 'normal' market conditions by 2025 and to phase out coal generation completely by 2030. The programme aims to add 1,800 GWh pa of new renewable generation by 2025 and 2,650 GWh pa by 2030. The Waipipi wind farm, developed by Tilt Renewables (now part of Mercury NZ) but underwritten by Genesis via a long-term PPA, provides the first 450 GWh pa. PPAs have also since been announced for 230 GWh pa from the Kaiwaikawe wind farm in Northland being developed by Mercury and 530 GWh pa from the Tauhara geothermal plant under construction by Contact Energy near Taupo. Genesis has also said that it is in discussions with two international parties towards developing 500 MW of solar capacity over the next five years, for an eventual contribution of 750 GWh pa.

Greater portfolio flexibility is a cornerstone aspect of Futuregen. Currently Genesis fuel flexibility is underpinned by management of its hydro assets and the Huntly coal stockpile. Futuregen seeks to reduce this reliance by seeking to recruit gas flexibility of 55 TJ/day of injection and withdrawal and 20 PJ of storage which broadly reflects the level of storage and flexibility provided currently by the Huntly coal stockpile (20 PJ of gas storage equates to ~900 kt of coal storage while 55 TJ/day of withdrawal capacity is sufficient to support ~240 MW of OCGT plant at full capacity).

Transmission

Two separate pipeline systems totalling 2,520 km connect producing fields in the Taranaki region with major industrial users and regional low-pressure distribution networks. The systems are owned and operated by First Gas and operate under an open-access regime with operator performance and pricing regulated by the Commerce Commission. The transmission system provides some linepack flexibility which can meet intra-day, however its extent is not material in the context of the sector's aggregate demand requirements and security margins.

Distribution

Distribution networks total 18,000 km of low-pressure pipelines that supply 280,000 industrial, commercial and residential customer connections. The main owners and operators of distribution assets are First Gas (Whangarei, Hamilton, Rotorua, Taupo, Whakatane, Gisborne, Tauranga, Wanganui, Palmerston North, Hastings and the Kapiti Coast), Vector (Auckland), Powerco (Wellington, Taranaki, Manawatu and Hawkes Bay), Nova Energy (multiple private and bypass pipelines in the Taranaki, Wellington, Manawatu and Hawkes Bay regions) and GasNet (Whanganui).

Financial

In addition to physical access and transactions, market participants also use a range of financial or hybrid physical and financial instruments and arrangements to manage fuel-related risks they face within and across asset portfolios. Most are conventional (eg price hedging as part of portfolio management) however some participants have introduced innovative new instruments to support portfolios. In a number of cases this has involved multiple generators agreeing to optimise their individual fuel positions for their mutual benefit and in doing so improve the overall availability and efficiency of the sector's thermal generating plant. The most gas-relevant of those include:

1. Gas tolling
2. Huntly swaptions
3. Market Security Options

1. Gas tolling

Since at least 2019, Contact Energy and Nova Energy have on regular occasions operated an arrangement under which Nova sells gas to Contact and then Contact sells electricity back to Nova. The agreement sees Nova direct gas that it would otherwise have sent into its own OCGTs into Contact's CCGT. The effect of the agreement is therefore essentially that of a processing or tolling agreement under which Contact processes Nova gas into electricity.

The deal benefits all parties. The higher efficiency of Contact's CCGT plant sees Nova receive back more electricity than it otherwise would have realised had it directed the same gas through its own OCGTs. Contact benefits from having third party gas to provide a minimum baseline to operate its CCGT, atop which it can add its own gas that it also would otherwise have likely had to direct towards its OCGTs instead of into its CCGT. The deal therefore served to improve the overall efficiency of the sector's thermal fleet, improve the utilisation of available gas and reduce the sector's per-unit emissions footprint. In April 2021, Contact announced a new tranche of its agreement with Nova covering 3.6 PJ of gas for delivery and processing during the upcoming peak winter period.

2. Huntly Swaptions

Between 2009 and 2022, Meridian Energy and Contact Energy (as Buyers) and Genesis Energy (as Seller) entered a sequence of separate but very similar agreements under which Genesis provided electricity hedge cover to them. The arrangements, known widely in the sector as "the Huntly swaption" agreements, saw Meridian and Contact pay a fixed annual payment of approximately $20-30m to Genesis for the option to call on Genesis during weak hydro periods to enter into a CFD to provide them with a fixed per-unit charge for electricity called. The strike price for called electricity was believed to sit above $100/MWh.

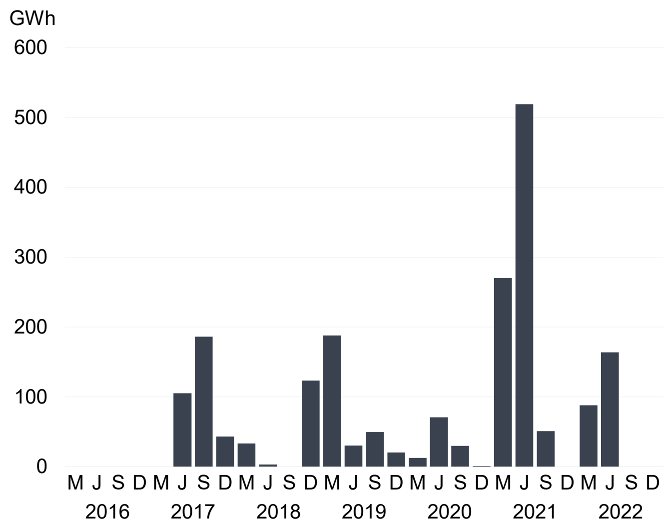
The effect of the swaption agreements was to underwrite the continued availability of individual Huntly Rankine units by funding the majority of the cost of refurbishing individual units ahead of the expiry of plant certifications. The timing of the original agreement and its subsequent extensions aligns with certification timings of individual units.

The original 2009 agreement lapsed in 2014 but was extended three further times. The most recent extension, announced by Meridian in April 2016, covered the four-year period from 1 January 2019 to 31 December 2022 and provided for 100 MW of year-round cover and 50 MW during winter (April to October) months. Contact Energy's most recent agreement also expired at the end of 2022 and was thought to involve lower volume but similar price terms. The expiry date coincided with the lapsing of certification of Rankine Units 1 and 4.

Between 2017 and 2022, Meridian and Contact called on swaption cover extensively as successive dry sequences and gas supply constraints produced high wholesale prices (Figure 10).

During 2022 the parties had been discussing terms for a further extension to the 31 December 2022 expiry however no agreement was reached. In August 2022, Contact (on the sell-side) and Meridian (buy-side) instead entered their own swaption and CFD agreements covering the two-year period commencing 1 January 2023. The swaption is for a maximum of 150 GWh pa callable between 1 April and 30 September in each of 2023 and 2024. The CFD is for 294 GWh pa. Both contracts were subject to Contact receiving confirmation from its main gas supplier (OMV) of delivery of a minimum amount of Maui-backed gas in each year to support its thermal generation.

Figure 10: Genesis Energy swaption calls, 2016-2022



Source: company data, Enerlytica

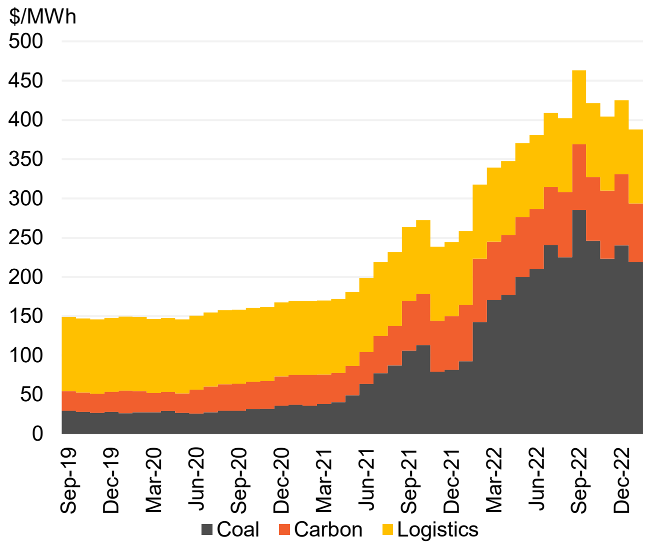
3. Market Security Options

Having not finalised a deal with Meridian and Contact to extend its existing swaption arrangement, in August 2022 Genesis launched a new swaption-like instrument, which it branded as "Market Security Options" (MSOs), targeted to the wider market.

The MSO pricing structure proposed by Genesis comprised a capacity reservation fee (CRF) and a strike price. The CRF was $125,000 per MW of reserved capacity per year, effectively inferring that the cost (including margin) of maintaining a Rankine to be available to call electricity from as $31m pa. The strike price structure Genesis proposed was based on spot market prices for international coal and local carbon and a levy to cover implied logistics and financing costs. Notably, the strike price structure is based on notional and not physical fuel. The effect of this is that while MSO buyers would pay for their cover at spot import parity-based pricing, Genesis would manage physical fuelling. This will allow it to switch between any of water (hydro), domestic coal, domestic gas and/or imported coal to meet its sell-side MSO obligations. With most of its on-hand coal stockpile acquired at comparatively low historic prices and with its carbon book fully hedged for each of its FY23 and FY24 at below $50/tCO2e, Genesis would likely realise substantial trading arbitrage gains under the proposed MSO structure.

With the ongoing conflict in Ukraine and the severe reduction to Russian energy flows into Europe, including coal, global energy prices have since 2021 been extremely high. Applying spot coal, FX and NZU prices to the formula set out in the MSO document implied a December 2022 MSO electricity strike price estimate of $390/MWh (Figure 11). Of the strike price, fuel accounts for $220/MWh, carbon $74/MWh and other constituents (principally logistics and financing costs) $94/MWh.

Figure 11: MSO strike price, 2019-2022



Source: Refinitiv, company data, Enerlytica

1.2 Needs analysis

In this section we analyse the extent to which the demand-side needs of the market are being met by the supply-side, and if they are not, what the implied 'gas gap' is. This assessment includes demand for and supply of both commodity (molecules) and capacity (flexibility) as described earlier in this section.

In making this assessment we have undertaken a segment-by-segment analysis. The four segments we isolate are:

1. Smaller industrials, commercial & residential (IC&R)
2. Large industrials
3. Electricity generation
4. Methanex

Notable is that our approach and assumptions have a conservative bias, reflecting that security of supply, by definition, must provide coverage for a range of unfavourable scenarios. This sees us compound negative scenarios from individual demand segments which, apart from Methanex for reasons we later explain, generates relatively large gross ACQ and deliverability shortfalls, particularly with generation gas demand.

1. IC&R

The IC&R segment comprises a relatively small number (around 100) of shared gas gates that in aggregate typically exhibit an operating range of we estimate 40-140 TJ/day (Figure 14). Variability is seasonal with the upper bound reflecting peak winter demand.

2. Large industrials

Operating profiles for each of the large industrial users we account for are summarised in Table 6.

The combined gas draw of the large industrials, including the dairy sector, the Kinleith pulp and paper mill, the Glenbrook Steel mill, and the Te Rapa cogen plant shows aggregate peak demand of 60 TJ/day. Load shape tracks the dairy season in showing a spring/summer bias, falling to as low as 20 TJ/day.

When the large industrials and IC&R segments are combined (Figure 13) there is a slight smoothing of the aggregate demand profile across the year. Overall standalone required flexibility is 50-60 TJ/day in each direction (injection and offtake) meaning a total spread between maximum and minimum demand of 100-120 TJ/day. On a standalone basis, the level of inferred storage required to meet this profile is 4-5 PJ.

Table 6: Major industrial site load profiles

Industrial	2020 Load Total PJ	2020 Load MDQ TJ/day	Comment
Dairy	8.9	38.6	Load follows the dairy season which shows a strong peak during spring months and a trough during the May to July period when seasonal herds are dried off. This demands a relatively high level of required flexibility, however the profile fits well with the underlying market and winter peak demand. On a standalone basis, to cover 90% of the flexibility it requires the dairy industry needs to be able to inject up to 20 TJ/day into storage and offtake up to 15 TJ/day during its peak season. Working storage of 2 PJ would likely be sufficient.
Ballance Agri-Nutrients	6.6	21.4	When operating normally the Kapuni AUP presents a stable load of 20-22 TJ/day. Downtime is a material consideration however with recent-year planned an unplanned outages/turn-downs accounting for nearly 20% of uptime. Nonetheless the AUP's normal profile is very stable and Ballance appears to have commercial arrangements with its supplier to accommodate demand variability. We therefore do not assume any flexibility as required.
Oji Fibre Solutions	2.8	17.1	Load into Oji's Kinleith mill shows a bias favouring winter/spring months with draw tending to drop over the summer months. This seasonality suggests an annual cycling capacity of around 0.3 PJ. On a daily basis Kinleith requires asymmetric support throughout the year, with the ability to access higher quantities of offtake up to 6 TJ to support peak daily demand in winter, and a lower and more sustained ability to store gas in the summer at rates of up to 3.5 TJ/day.
NZ Steel	2.0	8.6	NZ Steel's load profile over the past 2-3 years has been distorted by an unusual period during the first half of 2020 when major scheduled plant maintenance was followed immediately by COVID-imposed activity reductions during the lockdown period which delayed restart of the plant. Reduced load from November 2020 also appeared to coincide with the strategic review NZ Steel was undertaking at the time. Normalised load data outside of these periods suggests that required flexibility falls in a narrow range of +/- 2 TJ/day 90% of the time. Inferred storage capacity required reflects the flatness of this load profile at less than 0.3 PJ.

Source: Enerlytica

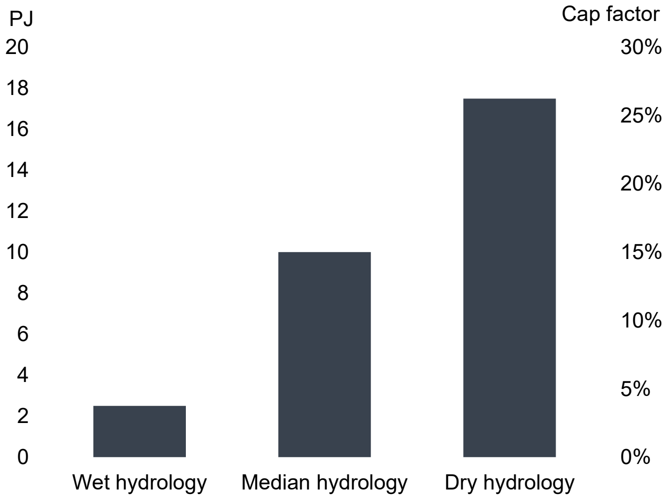
3. Electricity generation

Power generation is the segment that has the largest requirement for commodity and capacity flexibility. The range of potential scenarios the segment faces is large, reflecting a compound of varying potential outcomes across both demand and supply. Key determinants include hydrology, the performance and reliability of individual generation units, asset life cycles, strategic priorities of asset owners, post-2024 operation of the Tiwai Point aluminium smelter, the rate of demand growth and regulatory and policy settings.

In our analysis we focus on hydrology, the key variation in electricity supply and the impact that a dry year has on the call on thermal generation.

Concept Consulting estimates that by 2032, at which time renewable generation is expected to provide over 98% of electricity during a median hydrological year, the difference in the call on gas for power generation between the 10th and 90th percentile for hydrological years is as much as ~15 PJ (Figure 12). That is to say that gas demand could swing 7.5 PJ below or above gas demand of a median hydrological year, which is expected to be ~10 PJ. This 15 PJ swing between dry and wet years assumes Huntly uses coal or biomass for dry year cover and so could increase by a further ~4 PJ pa should Huntly instead use natural gas.

Figure 12: 2032 forecast gas-for-powergen demand



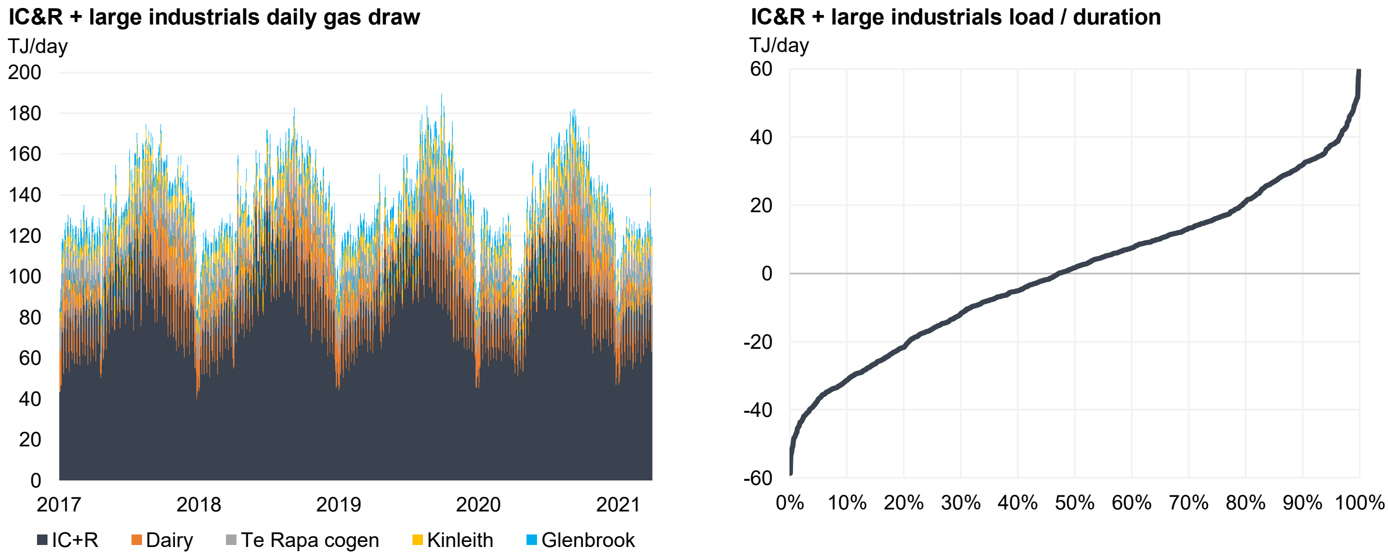
Source: Concept Consulting estimates, Enerlytica

While the range of uncertainty on gas demand for power generation narrows with time as decisions are made on key uncertainties such as the continuation or otherwise of operations at Tiwai Point and the rate at which future new generation build is brought to market, the owners of power generation assets are often required to negotiate multi-year gas supply agreements with upstream sellers to secure adequate gas supply. As such, thermal generators need to forecast gas demand for power generation often many years in advance.

Furthermore, the annualised scenarios do not account for load shaping. Seasonal demand, increasing load intermittency as renewable generation build continues and low incentives to build new standby fast start peaking generation means that the call on dynamic gas flexibility to meet peak demand is likely to increase significantly in high demand scenarios.

For example, dispatch from thermal generation estimated to be available to the market could vary by as much as 175 TJ/day but under dry hydrology the annualised capacity factor across all assets could simultaneously be as low as 25-30%. This could fall to as low as 4% under wet hydrology scenarios. Such low annualised capacity factors would bring financial pressure to thermal generators as they would have far fewer opportunities to generate revenue sufficient to recover their fixed costs and operating margin.

Figure 13: IC&R plus large industrials demand profiles

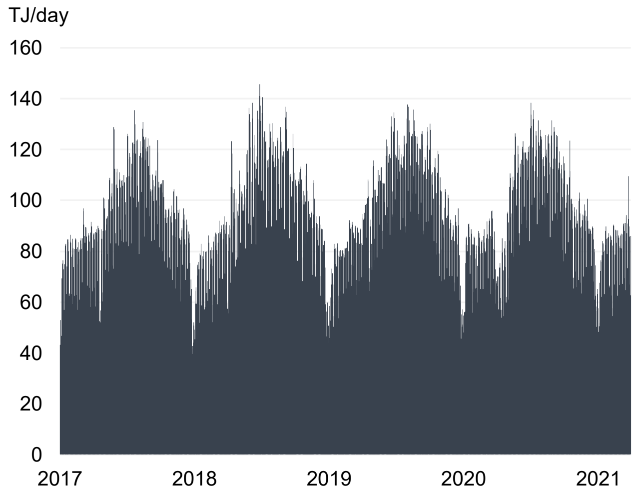


Source: OATIS data, Enerlytica

Source: OATIS data, Enerlytica

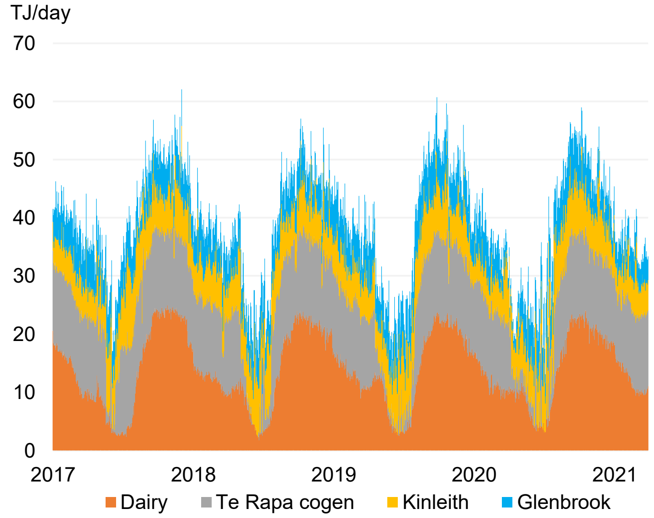
Figure 14: IC&R and large industrials demand profiles

IC&R daily gas draw



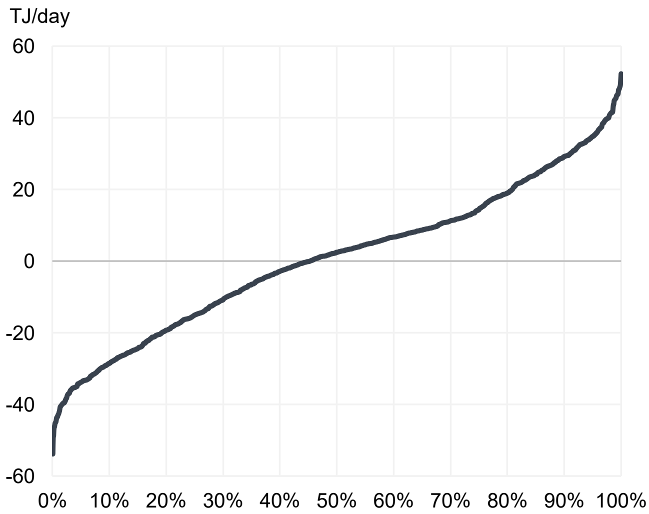
Source: OATIS data, Enerlytica

Large industrials daily gas draw



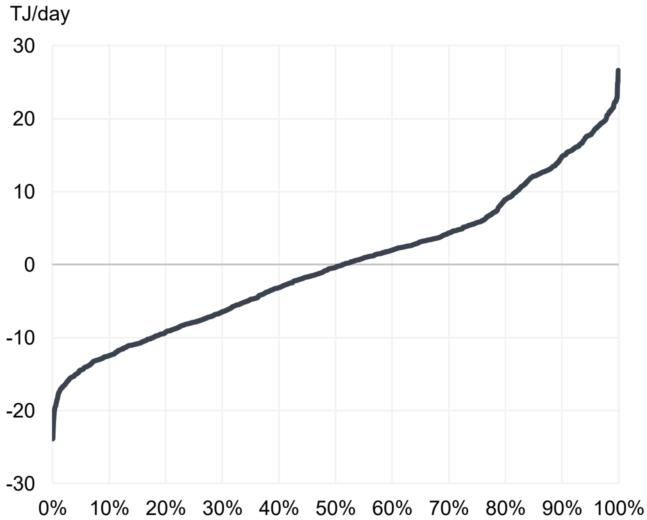
Source: OATIS data, Enerlytica

IC&R load / duration



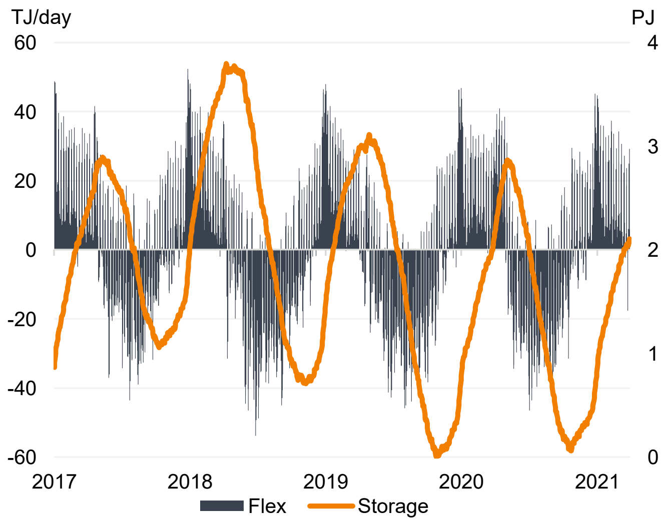
Source: OATIS data, Enerlytica

Large industrials load / duration



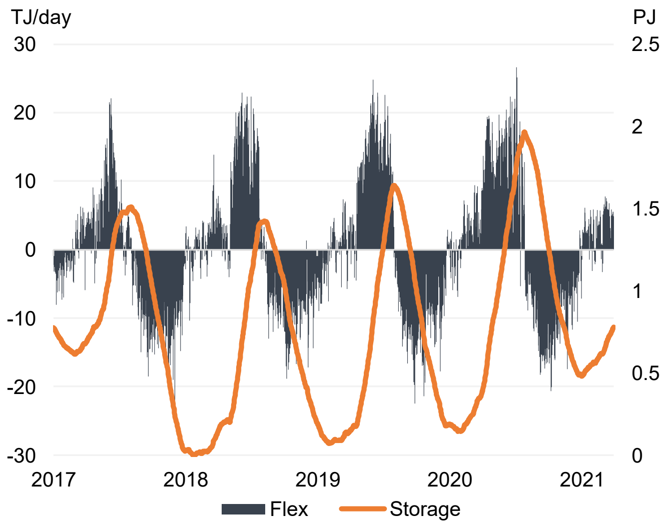
Source: OATIS data, Enerlytica

IC&R flex & inferred storage requirement



Source: OATIS data, Enerlytica

Large industrials flex & inferred storage requirement



Source: OATIS data, Enerlytica

Rankine fuel switching

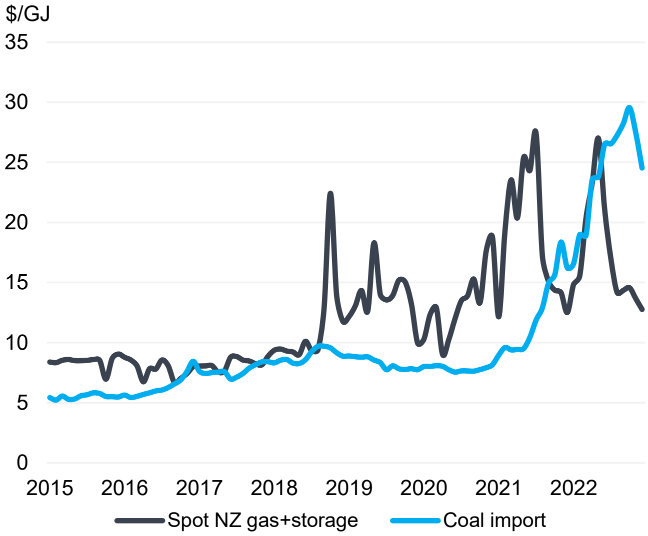
Over the five-year 2018 to 2022 period, a total of 3.6 mt or 79 PJ of coal was burned in the Rankine units, contributing gross CO_2e emissions of 7.2 mt at an average 1.4 mtpa.

Being able to access additional flexible gas on economic terms would allow Genesis to consider switching its Huntly Rankine units away from coal and towards gas. On an assumed 50% capacity utilisation across two-unit operation would reduce CO_2e emissions by 870kt, which at $\$50/tCO_2e$ would represent an avoided cost to the energy system of $43m pa.

On a commodity cost basis, until 2018 domestic gas and imported coal were broadly competitive on an underlying $/GJ basis even after accounting for the significant logistics costs involved with coal import. Since 2018 however each has shown significant volatility, for very different reasons (Figure 15). Following a long period of relative price stability across which spot gas averaged $5/GJ, well documented disruptions to Pohokura supply during 2018 saw pricing for marginal gas increase very sharply. This saw the cost of domestic gas increase to levels well above that of imported coal, the cost of which had remained broadly stable across the same time period.

This trend began to reverse from early 2021 when international commodity price benchmarks surged as buyers moved to rapidly procure energy supplies following the disruption to supply chains during COVID. This was compounded by Chinese restrictions on Australian coal imports imposed from July 2020 and in early 2022 when the Russian invasion of Ukraine saw widespread sanctions applied to Russian energy exports, pushing buyers to seek alternative supplies. As at December 2022, the all-in cost of indigenous spot gas including a provision for storage was we estimate half the equivalent cost of imported coal.

Figure 15: Monthly coal import parity vs spot NZ gas+storage, delivered at Huntly



Source: Enerlytica

4. Methanex

Methanex's operating model is essentially one of price arbitrage that it realises by reforming gas into methanol. More than 95% of its NZ production is exported and sold into the Asia Pacific petrochemicals market. It is therefore a very price sensitive gas buyer that has an ability to pay for gas that is typically below that of other segments. This is particularly the case compared to thermal generators in the current market which with high wholesale electricity prices can absorb marginal gas prices that are usually considerably higher than what Methanex can justify.

Methanex is a portfolio gas buyer that does not ringfence specific lines of source gas to specific plants. Following the idling of its Waitara Valley plant, Methanex has concentrated its existing gas entitlements towards the two Motunui plants that remain in operation. The result is that utilisation of its remaining installed capacity has increased but gross gas deliveries to it have fallen.

In respect of its ability to pay, Methanex could procure gas at pricing substantially higher than its average willingness to pay on an occasional basis to supplement lower-priced gas, for example if doing so would increase the efficiency of the overall reformation process. Nonetheless as an arbitrage producer that operates on relatively tight operating margins between domestic gas prices and international methanol prices we think it very unlikely that Methanex would see a commercial case for participating in any proposal to import and/or store LNG.

A more likely prospect, as has occurred in 2022 and 2023, could see Methanex looked to as a potential provider of (rather than buyer of) occasional fuel flexibility to other market participants via offering a form of physical or commercial demand-side response. The reality however is that across its portfolio Methanex is acutely focussed on applying gas it has contracted towards maximising the utilisation and efficiency of its plant. This effectively means that between turnaround cycles when plant is operating normally Methanex does not look to consider arrangements for it to provide demand-side response to other users in the market with gas it holds title to. Notable is that 2022 and 2023 have seen exceptions to this and seen Methanex reach agreements with at least one power generator to supply gas during winter, however its preparedness to do so in large part reflected turnarounds being undertaken on Motunui plants in each of those years, providing an opportunity for it to enter one-off gas sale and/or swap arrangements.

A far more likely prospect would be of Methanex supplying product methanol on commercial terms to local applications able to accept methanol into their processes, such as power generation. We investigate this option further in Section 4.

Aggregate sector demand

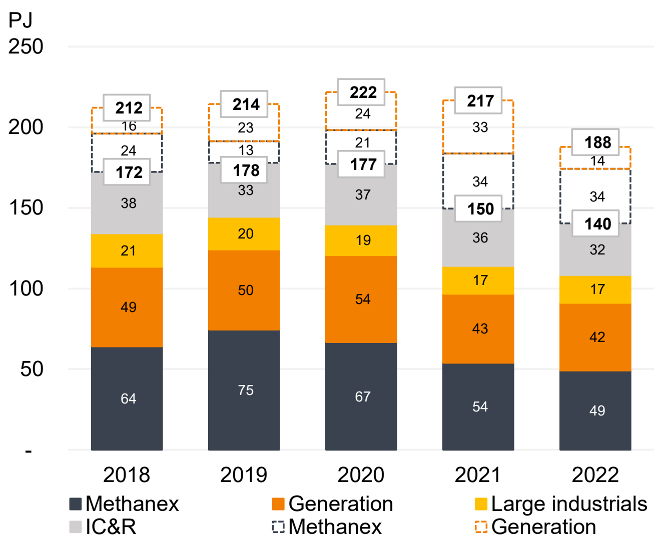
Commodity basis

Aggregating actual versus potential demand across the four demand segments indicates between 37 PJ (2019) and 67 PJ (2021) of unmet demand across the last five years (Figure 16). This represents demand that we classify as available to be supplied but was unable to be met due to insufficient gas availability. This is made up of two components:

- **Methanex** – Unmet demand of between 13 PJ (2019) and 34 PJ (2021 and 2022, reflecting that Methanex was unable to run its three plants at high capacity in most years. Capacity utilisation was highest in 2019 at 85% and lowest in 2022 at 60%.
- **Generation** – Unmet demand of between 14 PJ (2022) and 33 PJ (2021). This represents the electricity market's call on coal-fired Rankine generation which we infer as representing dispatch that (stockpile working capital issues aside) Genesis would have preferred to fuel on gas had sufficient gas been available.

Notable is that the unmet generation gas demand we identify only reflects like-for-like substitution of coal generation in each year. It does not account for market scenarios where demand for thermal generation could extend beyond the volumes shown for the 2018-2022 window. An extreme such scenario, for example in the event of a significant natural disaster that interrupts South Island supply, could see two or potentially even three Rankine units required to operate at high capacity for a prolonged period of time. Two units operating at 90% uptime would require 43 PJ pa which on the 2018-2022 estimates indicates a further 10 PJ (2021) and 30 PJ (2022) of standby potential demand.

Figure 16: Met vs unmet gas demand, 2018-2022



Note: solid bars reflect met gas demand, dotted bars reflect unmet gas demand

Source: Enerlytica

Flexibility basis

Across the four demand segments we estimate a requirement for up to 300 TJ/day of swing flexibility, 175 TJ/day of which is attributable to the generation segment.

The 175 TJ/day estimate for potential generation flex reflects the maximum fuel call that would feasibly be required to meet all 850 MW of gas-exclusive capacity currently in the market (Table 1) noting this excludes Te Rapa and TCC which Contact have already committed to decommissioning.

The 125 TJ/day balance reflects the IC&R and large industrial segments as presented in Figure 13.

Notable is that even if there was sufficient gas, flex and storage capacity available in the market, the thermal generators that require it the most would be unlikely to manage their demand uncertainty by committing to large and/or long-term take or pay contracts, placing sizeable volumes of gas into storage and by doing so make sizeable commitments to tie up large amounts working capital for an indefinite period of time as 'just in case' preparation for dry hydro sequences. This is especially the case given the uncertain policy environment posed by the 100% renewable by 2030 target and the Lake Onslow pumped hydro scheme. Storing 10-20 PJ of gas could feasibly require an upfront working capital commitment of up to $200m without any surety of recovery. Depending on market circumstances and prices, it could prove more commercially and economically efficient for generators to release stored gas to other undersupplied segments (e.g. Methanex) and subscribe to more flexible gas import solutions and/or demand-side response.

Also relevant is the risk posed by a current shortage of supply-side redundancy, particularly given the high concentration of production and maturing asset profiles that define the sector. If there was to be a significant unscheduled outage (as occurred in 2018 when Pohokura was offline for two separate repair outages and in 2011 when the Maui pipeline ruptured) or extended period of asset underperformance (Pohokura's accelerated decline an example) then indigenous supply margins could become quickly stressed. Financial and economic losses that are incurred by gas users and the wider economy during such significant unscheduled outages are sizeable and serve to enhance the case for seeking to increase supply-side redundancy.

2. LIQUEFIED NATURAL GAS

2.1 What is LNG?

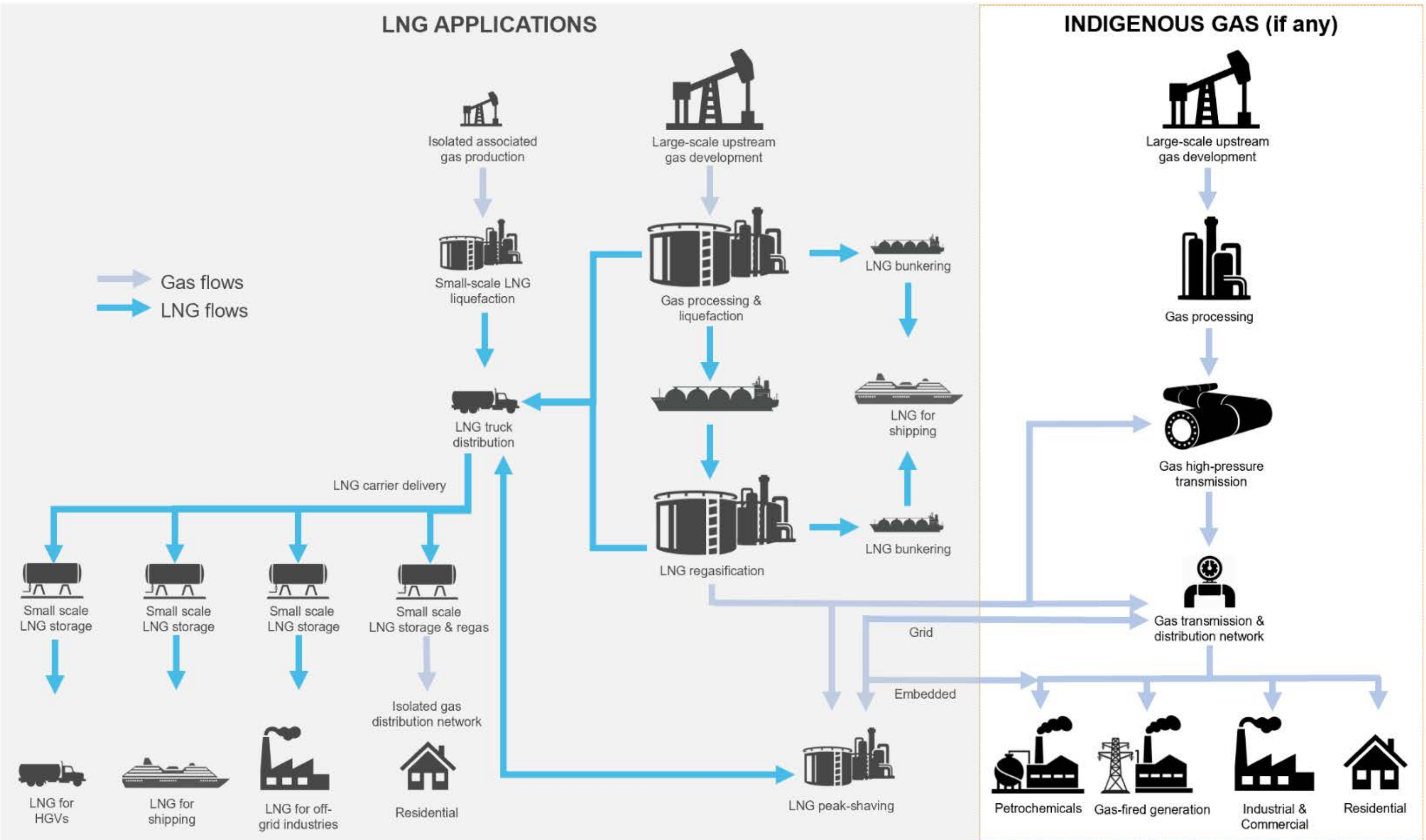
LNG is natural gas, largely composed of methane (CH_4) although often with small amounts of impurities such as ethane (C_2H_6), cooled via one of a number of patented refrigeration processes, to a temperature of minus 160° Celsius. At this temperature the gas condenses to liquid form (a process referred to as 'liquefaction') to occupy 1/600th of its normal gaseous volume.

Its energy density enables bulk storage and transportation via containment systems that are specifically designed to handle its cold temperatures. LNG can be transported via road, rail, and ship. At its destination LNG can then be vaporised to return it to its original gaseous state (a process referred to as 'regasification') from where it can be used in any conventional natural gas application, including to be injected into the gas stream for reticulation to industrial, commercial, and residential end users (Figure 17). As a fuel, LNG therefore presents all the advantages of natural gas but with the added benefit of greater energy density.

At its point of production, the liquefaction process sees feed-in gas cooled and depressurised to atmospheric conditions for easier and safer storage. LNG is retained in its cryogenic (very low temperature) state along the supply chain until it is returned to its gaseous state at its destination market or application. In other words, LNG's cryogenic intermediary form can simply be thought of as a type of virtual pipeline as it enables the carriage of gas from a point of production to a point of consumption.

This means that regasified LNG can be applied to any stationary or mobile energy application where natural gas is the fuel. Stationary energy applications therefore include the traditional channels of power generation, industrial, commercial and residential use. Mobile energy applications include land and sea fuels, particularly in energy-intensive, high-horsepower applications such as large sea vessels and heavy land transport vehicles where LNG is stored onboard in its cryogenic state and regasified to feed conventional gas engines.

Figure 17: LNG supply chain vs indigenous gas supply chain



Source: Enerlytica

2.2 Commercial applications

Commercial LNG operations began in the USA in the 1940s when the East Ohio Gas company started liquefying natural gas for the purpose of storing it to balance gas demand across seasons, particularly over the peak winter demand period.

Over its now 80-year history, LNG technology and markets have each matured dramatically. This is particularly so over the past two decades as floating production and handling concepts have been developed and scale economics have improved.

Advantages of using LNG include portability, flexibility, storability and certainty. The main disadvantage is that LNG is usually (but not always) a more expensive option than indigenous supply (Table 7).

Import LNG vs domestic LNG

LNG can involve either or both of imported gas and/or indigenous gas:

1. **Import LNG**: LNG is imported into a market from a LNG producer/exporter nation. Import requires the availability of receiving infrastructure. This has historically involved the construction of land-based terminals built to receive, store and dispatch large cargoes. A strong recent trend however has been of growth in floating storage and/or regasification facilities. The LNG itself is subject to international market pricing.
2. **Indigenous LNG**: LNG is produced from indigenous gas and is held as stored energy for release at a future time to meet local market demand applications. This requires the construction of both liquefaction and regasification infrastructure, albeit typically on a small scale compared to import channels. There are a range of options where LNG infrastructure can and does operate alongside indigenous gas production, including:
    - **Standalone liquefaction and storage**, with small and remote gas fields where the economics of connecting via pipeline to an existing transmission network may be prohibitive.
    - **Standalone liquefaction, storage and regasification**, for example at power plants where gas is procured from the pipeline system, liquefied, stored and then regasified for power generation during periods of peak demand and pricing (often referred to as peak shaving).
    - **Standalone storage and regasification**, for example where a large industrial site may opt to install onsite facilities to receive and store LNG to support existing onsite gas use and to provide access to pipeline-independent gas to mitigate the fuel risk posed by major system outages.

An important aspect of these options is that, in the case where an existing indigenous gas market exists such as in NZ, LNG serves to complement rather than substitute for indigenous gas. In other words, LNG stands in the market as supporting rather than replacing domestic production. This reflects the reality that the all-in cost of LNG is typically significantly higher than for indigenous gas, making it economic for only specific market applications and circumstances.

Safety

LNG is recognised as one of the safest hydrocarbon fuels to handle and manage. As it is typically stored in double-hulled insulated tanks the risk of loss of containment is lower than for many other more conventional hydrocarbon fuels.

If loss of containment does occur, LNG is non-toxic and leaves no residue when spilt. Instead, the LNG would evaporate and dissipate, initially as a vapour cloud created by water vapour condensing around the cold methane molecules. Any spill into the environment would therefore not require a major clean-up effort.

In its liquid state, LNG is not explosive, and its associated vapour cloud is also not explosive if it is not in a confined or congested area.

These features do not mean however that using LNG is without risk. If there is a loss of containment and the resulting vapour cloud does ignite, a “pool fire” could occur where a layer of the LNG would evaporate and burn. A pool fire would emit thermal radiation that would encourage more LNG to vaporise from the pool and from any nearby containment facilities, potentially feeding the fire.

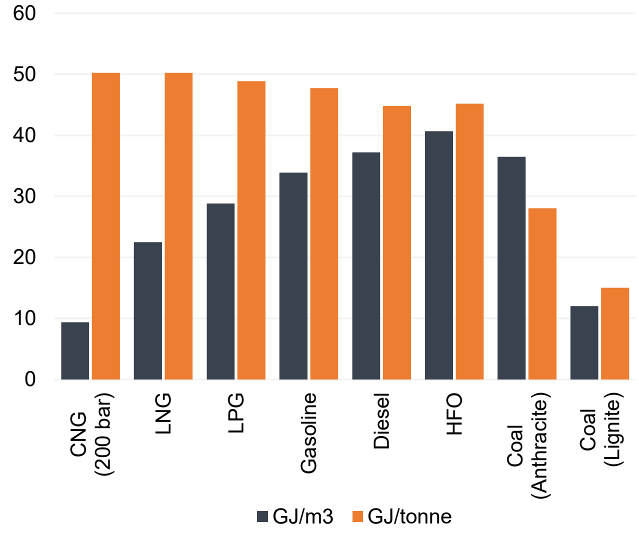
The main operational risk associated with handling LNG relates to cryogenic burns from coming into contact with the super cooled liquid and from possible asphyxiation by the vapour cloud should any be spilt. If LNG is leaked outdoors, the risk of asphyxiation is low but, being colder than air upon its initial evaporation, the methane gas in the vapour cloud will tend to stay close to the ground and is dangerous if it flows into confined spaces where it can displace oxygenated air.

Table 7: Generic advantage and disadvantages of LNG

Advantages	Disadvantages
• **Storability & flexibility**: Its greater energy density (Figure 18) allows for large volumes of natural gas to be stored at surface in a relatively small area anywhere that is strategically suitable for a containment facility. This contrasts to other forms of gas storage, such as below-ground depleted conventional natural gas reservoirs (old gas fields that have been emptied of their resource), or in cavities such as converted salt mines. Suitable UGS sites are relatively rare due to the specific geological characteristics they require and, even when they exist, the rate and quantities at which natural gas can be injected and extracted from storage is limited by the geology itself. With LNG, capacity and regasification send-out rates for delivery into gas grids or end use are at the outset designed and built to fit intended purpose of a project. • **Portability**: The ability to transport natural gas as LNG makes it a flexible and effective alternative to pipeline transport. This is particularly the case where pipeline construction is costly or impractical, such as across large and/or deep oceans, and within countries that do not have dense gas pipeline networks. LNG therefore can serve to avoid the cost and/or risk involved in components of infrastructure investment and allow natural gas to be delivered to users off-grid. • **Emissions**: As simply reconstituted natural gas, LNG provides a lower emissions footprint than many alternatives when users can switch away from lower-ranking fuels such as coal, diesel and fuel oil. • **Air quality**: Gas is clean-burning with virtually no particulate matter. Traditional fuel lines including petrol, diesel and heavy fuel oil carry heavy particulate content. It is principally for this reason that many heavily populated cities that suffer from poor air quality, particularly in Asia, have put in place policy programmes to replace legacy heavy vehicle fleets with clean-burning alternatives, including EVs and natural gas-variant vehicles. In many cities, such as Shanghai, these policies have achieved extraordinary success towards improving air quality. Similar initiatives to improve the marine industry and reduce the widespread use of high-sulphur fuel oil has seen a sharp increase in gas-based shipping options including LNG and methanol. • **Security of supply**: From an energy security perspective, the optionality provided by being able to import and export LNG to and from facilities spread around the world is more favourable than relying exclusively on pipeline gas. The recent construction and upgrading of LNG facilities across Europe has helped to reduce European reliance on Russian pipeline gas by providing an inlet for trans-Atlantic LNG volumes and providing negotiation leverage in gas price negotiations with suppliers.	• **Handling**: Handling LNG requires specialised cryogenic equipment which means that capital and operating costs tend to be higher than for other fuel systems. LNG cannot be stored indefinitely and presents boil-off which must be managed. As a fuel LNG is therefore best suited to demand centres that have firm ongoing demand. Operationally, LNG requires additional training for staff to be able to manage and handle the fuel. • **Cost**: The steps of liquefaction, storage and distribution, and regasification involved with producing and moving LNG create additional steps in the natural gas supply chain that increase its cost. Similar to crude oil, periods of global over or undersupply has produced periods of significant price volatility that has seen international cargoes trade for more than NZ$105/GJ and as little as NZ$4/GJ.

Source: Enerlytica

Figure 18: Energy density of common stored fuels



Source: industry data, Enerlytica

Seaborne LNG trade

Seaborne trading of LNG began in 1959 with a cargo shipped from the USA to the UK. In 1964 Algeria became the next exporting nation, delivering to the UK and France, with Alaska soon following with LNG cargoes delivered to Japan. By the 1970s Brunei, Indonesia, and Persian Gulf nations followed with their own export projects, largely to Japan, South Korea and Taiwan. LNG demand increased sharply during the 2000s on a push for cleaner and cheaper energy in North America, Europe, and then Asia, particularly as oil and coal prices increased driven by Chinese demand growth.

Seaborne LNG transport enabled large upstream gas discoveries that were previously too far from existing markets to be developed. In the early years of LNG trading a development would be built to commercialise a specific upstream discovery or set of discoveries and with a specific market destination as part of its development case.
LNG trade was therefore dominated by long-term contracts for point-to-point supply. Tight contracting saw relatively few "spot" cargoes become available. LNG sale and purchase agreements (SPAs) of the time were classified as "Delivered Ex-Ship" (DES), also known as "Contracts, Insurance and Freight" (CIF), meaning the point of contractual cargo delivery was at the LNG buyer's receiving facility with the seller responsible for the cost of insurance and freight. This saw many liquefaction project developers commission their own shipping fleets to be able to meet delivery obligations.

Into the 2000s, the increasing number of sources and destinations for maritime LNG allowed oil and gas companies and commodities traders to run portfolio models of LNG trading whereby a dedicated business unit would act as middleman between sources and destinations of LNG with investments in upstream and downstream projects. This allowed for a much more liquid and flexible market as arbitrages and shipping positions were able to

Box 1: Prelude FLNG

Prelude is a remote production facility located entirely at sea 200km off the Australian Northwest coast. The facility, which is operated by Shell on behalf of a JV that includes co-venturers Inpex, KOGAS and OPIC, comprises a 488m long vessel moored permanently in 248m of water. It is the largest vessel ever put to sea.

First production was achieved in December 2018 and following ramp-up its first LNG export cargo was shipped in June 2019. Sales product is offloaded to shuttle LNG, oil and LPG carriers which moor alongside the FLNG vessel to load their cargoes.

The vessel handles production from the Prelude and Concerto gas-condensate fields which are together estimated to house between 3,000 and 5,000 PJ of recoverable gas. On board the vessel is all extraction, treatment, separation, liquefaction and storage equipment and facilities to produce 5.3 mtpa of natural gas liquids comprising 3.6 mtpa of LNG, 1.3 mtpa condensate and 0.4 mtpa of LPG. This equates to annual capacity production of 198 PJ gas, 12 mmbbl condensate and 400 kt of LPG. These metrics make Prelude highly comparable in scale to the Maui gas-condensate field.

The vessel is expected to be onsite for 25 years but has been built to handle 1-in-10,000 year weather events including tropical cyclones. One of the major advantages of the FLNG production concept is its mobility which will enable the vessel to be redeployed once the field has been depleted and protects against many of the risks that traditional land-based concepts face including the risk of asset stranding in the event of unexpected reservoir performance or security issues such as an adverse change in a host nation's political stability.

Prelude LNG cargo offload to carrier

be optimised. As a result, LNG sale agreements from liquefaction facilities tended towards “Free Onboard” (FOB) sale types where the portfolio buyer of LNG was responsible for their own shipping to collect LNG from the export facility. This allowed labour to be divided, with portfolio LNG traders chartering vessels from shipowners to meet portfolio needs. Cargoes and vessels could then be swapped as needed. In the last decade, the industry has matured rapidly as new supply has arrived to market (from Australian coal seam and Northwest Shelf gas and US shale gas in particular) and strong demand growth (China and emerging markets in particular) has increased liquidity. New technologies have also reduced the cost of infrastructure development. A particular trend has been the emergence of Floating Liquefaction and Storage Units (known as FLSUs or FLNGs) and Floating Storage and Regasification Units (FSRUs) which have enabled LNG handling infrastructure to be built in shipyards that provide a greater ability to control costs which are typically well below that of conventional onshore facilities. Floating infrastructure has also supported the commercialisation of gas fields that previously may not have been viable due to their location and/or local market conditions. Many FLNG and FSRU projects have also involved repurposing existing LNG vessels with liquefaction and/or regasification equipment, serving to reduce costs and salvage waste. More recently, the Russia-Ukraine crisis has brought about dramatic changes in LNG trading, described further below.

LNG liquefaction

LNG liquefaction terminals have traditionally been sized to suit the gas fields or flows they are intended to handle. Liquefaction facility sizes are typically quoted as million tonnes (mt) of LNG they can liquefy and deliver per annum and the number of “trains” they have, which refers to the number of independent liquefaction processing lines onsite. The greater the number of trains (called trains because equipment is usually arranged in a line, like a train) the greater the ability to cope with redundancy, although this comes at the expense of cost and energy inefficiency. Most export facilities have at least two trains operating onsite.

Large liquefaction facilities typically use one of a handful of liquefaction technologies which vary according to processes and refrigerants used. Smaller liquefaction facilities, such as peak shavers, will typically have different economic drivers than larger projects, given a need to operate more simply and with lower capital costs. They often as a result employ less complex refrigeration technologies. The largest LNG liquefaction facility and export terminal is in Ras Laffan, Qatar, which produces from the world’s largest gas field and has seen Qatar become the world’s second largest LNG exporting nation (Figure 19). The facility exported more than 77 mt (4,235 PJe) of LNG in 2022 through 14 trains, with the largest rated to 7.8 mtpa (430 PJe pa). Land based liquefaction facilities are usually less than 10 mtpa in scale and have cost NZ$15-56 bln to develop at a capex-equivalent of US$1,470-2,450 per tonne of capacity.

Box 2: Klaipeda FSRU

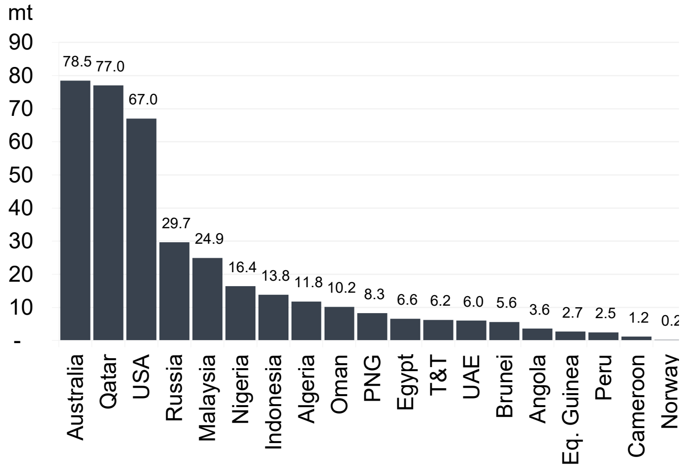
The Klaipeda LNG FSRU project, based in Lithuania, commenced operations in 2014 as a means to reduce dependence on Russian pipeline gas. The FSRU “Independence” cost US$330m to construct and is leased from Hoegh LNG. It can store 170,000 m^3 (4.2 PJe) and export up to 165 PJe pa into the local and surrounding markets.

The terminal, partially financed by the EU, is owned and operated by Klaipedos Nafta, Lithuania’s state oil terminal operator. The state natural gas company, LDT, its subsidiary gas trading company LITGAS, and the largest domestic gas consumer, private fertiliser company Achema, are the principal customers with capacity reserved for each. Remaining capacity is available to neighbouring Estonia and Latvia which share pipeline connections with Lithuania. LNG cargoes have been procured jointly among its users as well as independently on both multi-year and spot contracts. Reflecting the supply security the facility provides, all Lithuanian gas customers pay a levy to maintain the FSRU. This model is not without controversy however, with Achema, which accounts for half of Lithuanian gas demand, supporting the move to import LNG but has taken legal action against the levy which it claims is a form of state aid that breaks EU rules, forcing private companies such as itself to underwrite public sector entities.

A smaller scale LNG supply chain has been built on the back of the FSRU and it has now become a base for bunkering and break-bulk operations in the Baltic region. Through a bunkering vessel, the FSRU can distribute LNG throughout the Baltic Sea and feed a nearby 5,000 m^3 (125 TJe) onshore storage and truck loading facility that distributes LNG to fuelling stations and off-grid industries in the region. In 2020, PGNiG, a Polish oil and gas company, was awarded rights to all capacity at the facility.

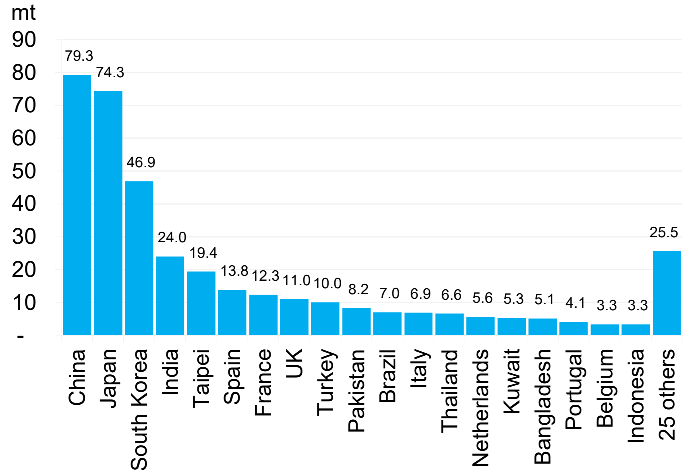
Klaipeda FSRU

Figure 19: LNG exporting nations, 2021



Source: IGU data, Enerlytica

Figure 20: LNG importing nations, 2021



Source: IGU data, Enerlytica

The smallest commercial LNG liquefaction facilities are containerised "cryobox" solutions that can deliver 37 m^3 (1 TJe) per day of LNG each, or 0.005 mtpa (270 TJe pa) when averaged out over the course of a year. These are often used in combination to liquefy gas at small, unconventional, "stranded" upstream assets such as shale gas wells that are far from pipelines. The concept has been particularly successful in Argentina where it has enabled smaller upstream developments to develop and deliver LNG via truck directly to power stations that have their own LNG receiving and storage facilities.

Four floating LNG liquefaction projects are also now operating, the most notable of which is Shell's Prelude project off of Northwest shelf Australia which can produce 3.6 mtpa (198 PJe pa) of LNG (Box 1). The smallest FLNG/FLSU in operation is the FLNG Hili which was converted from a conventional LNG cargo vessel and can process 2.4 mtpa (132 PJe pa). The smallest FLSU currently operating is the FLNG Tango which can process 0.5 mtpa (28 PJe pa), although it is currently between projects and is expected to redeploy to Congo later in 2023.

LNG Regasification

Regasification describes the process of returning LNG to its gaseous state at its ultimate destination from where it can be injected into the gas stream. Depending on the scale of the storage facility and the end use of the LNG, regasification can be done either via natural vaporisation (or "boil-off") which occurs with gradual heat ingress, or controlled directly and accelerated by feeding LNG through pipes inside water baths, encouraging the LNG to vaporise more rapidly.

As has been the case with the liquefaction process, regasification terminals have historically taken the form of large-format land-based facilities designed to handle very large volumes of product. In the mid-2000s the first floating regasification formats were brought to market. FSRU technology has since become mainstream as project developers have been attracted by the scalability, flexibility and controllability of the capacity it offers. Nearly 50 FSRUs are now in continuous operation around the world.

Some regasification facilities use the cold temperatures of LNG to facilitate the extraction of nitrogen and oxygen from the atmosphere which can then be sold and, in the case of nitrogen, fed into the gas stream to control gas spec or used as an inert gas to displace any oxygen in pipework and storage to ensure safe operations.

Unless LNG is actively refrigerated in storage, which is not typical, a degree of methane gas boil-off will always occur and can build up in LNG storage tanks. If allowed to boil-off for too long, the gas pressure in LNG storage tanks can increase and the purity of the LNG remaining in the tank can decrease, as methane preferentially evaporates ahead of other impurities, to potentially unacceptable levels.

Boil-off gas rates are typically in the range of 0.1-0.15% per day for larger scale LNG ships and storage terminals (typically over 120,000 m^3 or 3 PJe) and up to 0.75% per day for smaller containers (of typically 50 m^3 or 1 TJe) depending on the level of insulation of individual storage units.

Boil-off gas can be managed by directly feeding it to end use applications, such as into a local market gas grid or deploying it as fuel into onsite generation and/or heat plant. Gas can also be re-liquefied via an onsite refrigeration unit dedicated to handling the small quantities of boil-off gas. In extreme cases, when other boil-off management methods are disrupted, gas can be vented into the atmosphere.

Box 3: Benoa LNG

Located in Denpasar, Bali, Benoa LNG consisted in its first phase of operation of separate FSU and FRU units installed to receive LNG and supply gas to a nearby 200 MW gas-fired power plant. The facility entered operation in March 2016 after passing FID less than a year earlier.

The project developer, state port operator Pelindo Energi Logistik (PEL), opted for a separate FRU and FSU as an interim solution prior to commissioning a smaller integrated FSRU designed for the site. This was because of limited space within the port environs and because larger ships are more difficult to operate in Balinese waters.

The FSU holds 26,000 m^3 (620 TJe) of LNG and is served by the Triputra LNG carrier delivering cargoes of up to 22,500 m^3 (540 TJe) from LNG liquefaction projects operating elsewhere in Indonesia.

The FRU was barge-mounted and took only 8 months to build because of its simple design. Built by South Korean engineering firm Gas Entec, it had a feed pump rated to 100 m^3 per hour and a gas feed-in rate of 50 mmscf/day (53 TJ/day).

The entire project can deliver 0.3 mmtpa (16.5 PJe) of LNG and reportedly cost US$100m (NZ$140m) to complete.

A key enabler of the project was that it sits as part of a suite of smaller scale projects around the Indonesian archipelago built by PEL, improving the economies of scale around which a dedicated supply chain was able to be developed. In addition, the Triputra LNG carrier, which was built in 2000 originally to deliver Indonesian LNG to smaller cities in Japan, was already operating and available to service these projects.

Benoa FSU (right) and FRU barge (left)

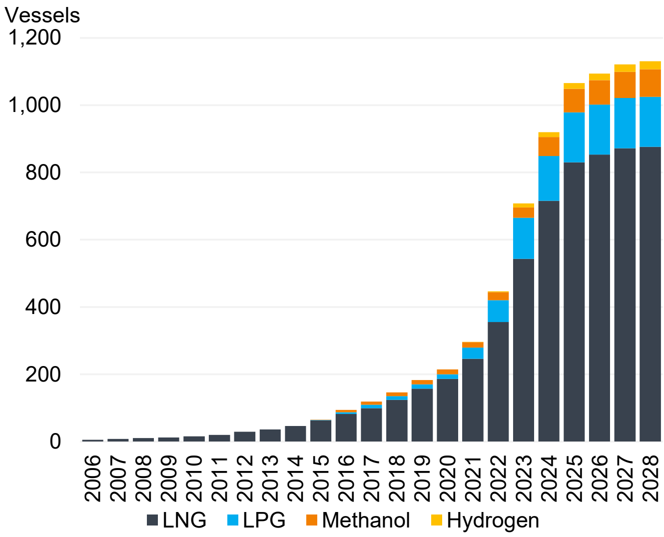
Smaller-scale LNG

While the majority of LNG infrastructure internationally is purposed towards servicing the large-scale international seaborne trade, there have been rapid recent advances in developments for smaller scale and floating LNG applications. These advances allow infrastructure to be built in specialist fabrication yards and led to dramatic cost reductions and faster development times. The smallest scale applications focus primarily on LNG as a maritime fuel, heavy goods vehicle fuel, and fuel for heat and power to serve off-grid industries. While there is no strict size definition for what constitutes small-scale, an industry rule of thumb is that projects designed to handle less than 0.5 mtpa (27 PJe pa) of LNG are regarded as small relative to most facilities operating around the world.

Maritime fuel

LNG was traditionally only used as a maritime fuel in a handful of locations, such as Norway, but has grown rapidly over the last decade in part due to new restrictions on sulphur emissions imposed by the International Maritime Organisation (IMO) which came into effect in 2020. While penetration is still relatively low compared to other low sulphur fuel solutions, such as the use of emission scrubbers or low sulphur diesel and fuel oil, its market share is expected to continue to grow rapidly (Figure 21). Traditional LNG players have been leading the rollout of LNG bunkering solutions with 30 active LNG bunkering vessels and 16 to be delivered including one to serve the Australian east coast. Cruise ship operators are among the biggest customers but uptake is also growing quickly in other shipping segments. A major reason for uptake by the cruise ship industry is that liners tend to stop at inner city wharfs where authorities require them to comply with more stringent pollution and noise restrictions.

Figure 21: Demand growth of alternative shipping fuels



Note: excludes LNG carriers from LNG-fuelled numbers

Source: DNV GL data, Enerlytica

Box 4: LNG in Brazil as dry year cover

Brazil's electricity supply typically sees 70% of demand met from hydro generation. A fleet of natural gas-powered CCGTs integrated with LNG import facilities plays a critical role in providing dry year cover for the country's electricity network.

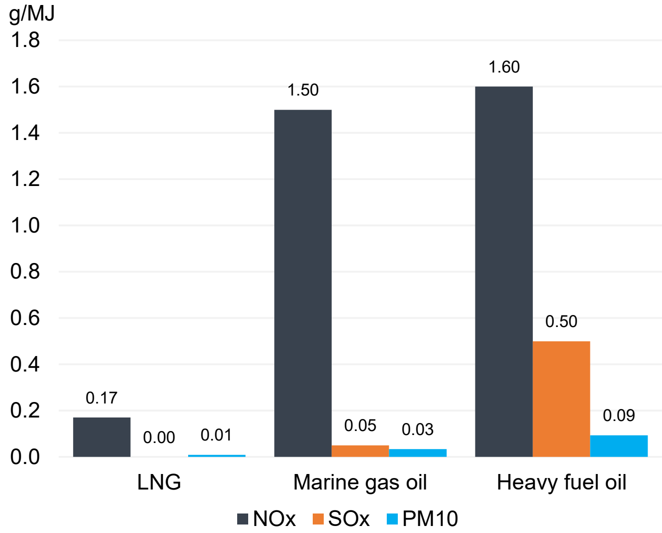
The value of this diversity was highlighted in 2021 when Brazil experienced its worst drought in more than 90 years. The drought coincided with planned maintenance at major local domestic gas supply facilities and declining supplies from neighbouring Bolivia. As a result, Brazil imported record volumes of LNG to feed its CCGT fleet to meet electricity demand of its population of 220 million.

The move to steer towards LNG import dates back to 2001 when a major power shortage, which was also caused by drought, caused energy shortages that crippled the economy. LNG is now received through five import facilities along the Atlantic coast, with all five based on FSRU concepts. The oldest of these facilities began operating only in 2009 with three backed by national oil company (NOC) Petrobras. Some of the projects were commissioned alongside integrated onshore CCGTs.

As Brazilian LNG demand depends on hydro output and therefore catchment levels, the country has not been a consistent, baseload destination for LNG cargoes. This may change however as most forecasters expect gas to double its share of the Brazilian electricity mix, from 7% to 15%, to meet demand growth for both baseload and peak electricity.

Porto do Acu FSRU project in Brazil

Figure 22: Marine fuel NOx, SOx & PM10 emissions



Source: IGU data, Enerlytica

As well as bunkering, it is also increasingly common to fuel ships with LNG from trucks once they are in port, allowing them to be fuelled in a variety of locations.

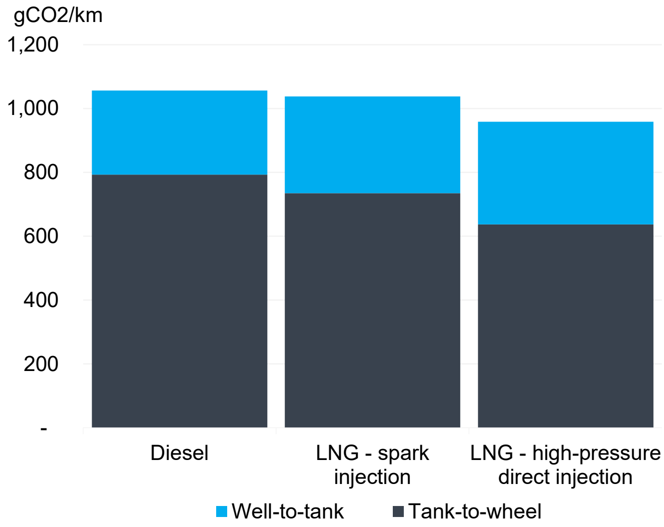
Heavy road transport

LNG has also seen strong recent-year growth in high-horsepower land freight applications in market settings where air quality (Figure 22) and emissions (Figure 23) are priorities. Partnering arrangements can also provide fleet operators with greater certainty and control over their fuel costs. In most cases, LNG can be a direct substitute for traditional diesel applications.

The supply chain requires a trucking loadout facility to be attached to a LNG storage facility. These facilities can either be integrated with a LNG import facility or can be located remotely as a dedicated storage and loadout base to act as a satellite supply hub, in much the same way as a traditional service station forecourt.

On the trucks themselves, LNG serves simply as the method of onboard fuel storage. Trucks fill directly from the loadout facility and LNG is stored onboard in a cryogenic tank similar in size and capacity to typical diesel tanks. LNG is released as needed and vaporised to return it to its gaseous state. Trucks use standard combustion engine technologies, typically either spark ignition (SI) or high-pressure direct injection (HPDI). SI variants have the gas and air pre-mixed before entering the combustion chamber that can result in lower thermal efficiency and higher emissions while HPDI variants are more similar to diesel engines and require a small amount of diesel to aid ignition. This does allow for HPDI engines to be dual-fuelled however, running on either or both LNG and/or diesel.

Figure 23: LNG vs diesel well-to-wheel GHG emissions



Source: ICCT data, Enerlytica

To date the uptake of LNG heavy goods vehicles has been strongest in China where regulations introduced in 2007 to improve air quality supported growth. The latest estimates are that China has an estimated 600,000 LNG-fuelled trucks and buses on the road serviced by more than 3,000 filling stations with total demand for its road transport sector equal to 13 mmtpa 715 PJe. The US and Europe are the next most established markets for LNG trucking, with around 150 and 300 filling stations respectively and more than 15,000 LNG trucks on the road in Europe. Low gas prices have supported growth in the US while European growth has been supported by policy programmes and subsidies.

Off-grid industrial applications

LNG for off-grid industrial applications is still a relatively niche sector globally but has made particular headway, again, in China, the US, and Europe where its uptake has displaced legacy coal, LPG and heating fuel applications.

Customers for off-grid LNG tend to be relatively large energy users (>1,000 m^3 or >25 TJe pa) with a flat demand profile that enables the investment in cryogenic storage and modified boilers to be cost effective and for the inconveniences of boil-off management to be minimised. Agriculture, aquaculture, food processing, and mining are particularly prevalent adopters. LNG to meet island power demand has also grown in archipelago countries such as Indonesia.

Regional seaborne LNG is typically quoted on a per million British thermal unit (mmbtu, with one mmbtu equivalent to 1.055 GJ) basis while trade quantities and processing facility capacities are quoted in millions of tonnes per annum (mtpa, 1 mtpa = 55 PJe). Storage facilities and LNG cargo vessels are quoted in thousands of metres cubed (m^3) with one metre cubed equalling circa 25 GJe.

Box 5: Dunkirk LNG truck loadout

Construction of the Dunkirk LNG terminal in Northern France began in 2011 and it was commissioned in 2017. It is the second-largest LNG regasification terminal in Continental Europe and connects by pipeline with each of the French, UK, Dutch and German gas markets.

It has three 200,000 m^3 tanks that can together hold 14.9 PJe of gas. It has capacity to regasify up to 13 bcm (490 PJe) pa of gas.

In 2020, a new truck loading bay was added to the terminal to enable LNG trucks to be filled onsite. The facility allows for self-loading of LNG trucks and containers and offers up to 3,000 capacity slots pa. The facility operates on an open access basis and slots are available 24/7 with trucking operators able to book slots directly online. A full cargo can be loaded in 90 minutes at a flow rate of 90 m^3 per hour (2.2 TJe per hour). Customers include transport operators, bunkering and remote industrial users.

Dunkirk LNG terminal

LNG truck loadout

Pricing

Import LNG

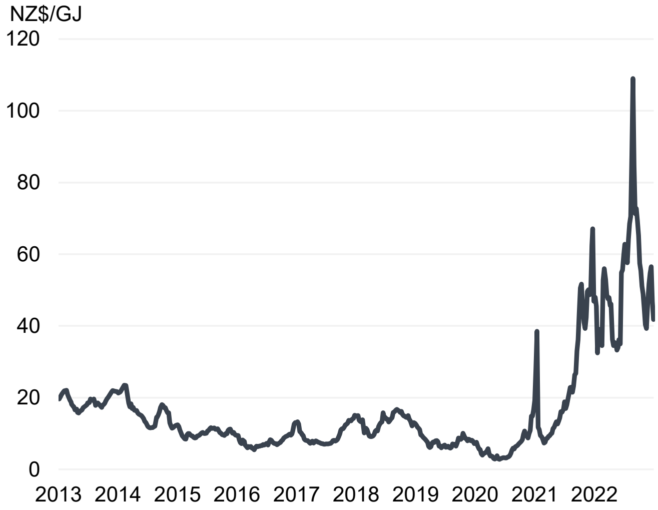
As trading in seaborne LNG has increased, LNG contracts and pricing arrangements have matured. Up until the 2010s, LNG projects were typically underpinned by 20-30 year SPAscovering millions of tonnes of LNG pa between buyer and seller. These contracts typically specified fixed quantities of LNG and provided for nomination ranges, usually of plus or minus 5-10%, with which buyers or sellers could increase or decrease contracted sale volumes.

Landed LNG prices in Asia were typically indexed to oil, and in particular the Japanese Crude Cocktail (JCC), a benchmark published by the Japanese government based on the average price of Japan's oil imports. This was used in part because Japanese electricity generators, which continues to be a major demand segment for LNG, operated power plants that could burn either gas or oil and sought relatively uniform pricing per unit of calorific value between the two. LNG sold under long term contract to North America and Europe, which had much more diverse and mature local gas markets and gas market trading, would instead be priced at a discount to local gas market price benchmarks such as the UK National Balancing Point (NBP) price. This was so LNG buyers could still make a margin after injecting the gas into the local distribution system and incurring pipeline fees. Any extra cargoes produced or needed were bought and sold separately in a relatively small spot market. Today, the spot market is deep, liquid, and heavily traded. Sale agreements that are only a few years in duration and smaller in volume are also much more common and new liquefaction projects no longer need to contract all their future volumes to be able to attract finance.

Newer long-term LNG contract prices in Asia are also gradually breaking their indexing with crude oil, trending increasingly towards "pure" gas prices that reflect the supply/demand balance of LNG itself rather than other hydrocarbons. This is evident in the progressive moving away from oil-indexed mechanisms, such as JCC in favour of gas-indexed alternatives, such as the Japan Korea Marker (JKM) which is a published average of delivered LNG spot prices independently negotiated between buyers and sellers in the region and upon which an entire futures and derivatives market has become established around. The Henry-Hub (HH) US gas price is also increasingly relevant due to the number of new large-scale LNG export projects being built underpinned by US shale gas.

Today new LNG sale and purchase agreements for multiple cargoes can be indexed to JCC, JKM, HH, European hub prices and even a mixture of these and other benchmarks. This, along with increasing competition for spot cargoes, particularly during the Northern Hemisphere winter, is seeing increasing price convergence among LNG importing regions.

Figure 24: JKM LNG price benchmark, 2013-2022



Source: Refinitiv data, Enerlytica

Notable however is that while the IGU reported in 2021 that up to 30% of new LNG trades were through more novel gas-only indexed pricing, 55% remained priced through legacy contracts that may have five years or more left to run before they lapse. Via nomination rights, these contracts can serve to bracket the pricing of spot LNG cargoes. Previously the trend was against signing long term supply contracts, however with volatility and high spot prices brought about by the Russia-Ukraine conflict, buyers are seeking certainty of pricing which could see a return to decadal length contracts and indexing of gas to competing fuels, at least on a partial basis.

Impact of Russia-Ukraine war on LNG markets

The sanctions placed on the export of Russian pipeline gas sales into Europe as a retaliatory measure to European sanctions imposed on Russia following its invasion of Ukraine has seen dramatic shifts in LNG markets over the past 12-18 months.

Pre-Ukraine, Russian imports typically met 40% of European gas demand with some countries, such as Germany, particularly dependent on Russian gas to support its energy system. The dependence is even greater on Russian coal which pre-Ukraine accounted for 70% of EU thermal coal imports. Coal also served as an important competitive alternative to natural gas in the power sector, helping to cap the price of natural gas.

With increasing embargoes, sanctions and price caps placed onto Russian hydrocarbon sales into Europe, the result has been a wholesale recasting of global hydrocarbon trade flows. Russia is now having to accept much lower sale prices for its hydrocarbons as it redirects exports previously destined for Europe towards countries such as China and India that have positioned themselves as neutral to the Ukraine conflict.

Europe's scramble to replace Russian gas has brought heavy disruption to global LNG markets, turning it from a market of last resort to that of a premium bidder now setting spot prices. Europe's 41 existing LNG receiving terminals can import more than 10,000 PJ pa or 40% of Europe's normalised (pre-Ukraine) gas demand and can collectively store 275 PJ at any one time. The reduced flows of Russian pipeline gas saw European gas retailers and governments move to source as much LNG as possible to meet demand and fill domestic storage in an effort to see that Europe would have enough gas to meet its winter 2022-23 demand peaks. To attract LNG traders to deliver cargoes to Europe, European LNG buyers had to set record spot LNG prices to encourage sellers to break their sales agreements with other contracted buyers, many of which were in Southeast Asia. Front month prices for LNG sales into Asia approached US$70/mmbtu in late August 2022, equivalent to NZ$108/GJ, but have since reverted back to around NZ$15/GJ.

LNG traders also needed to secure as many LNG vessels as possible as quickly as possible to ensure LNG was being supplied at fast enough rates to fill the gap left by Russian pipeline gas. This saw charter rates hit extreme levels to a reported US$400,000 per day in October 2022.

Despite European LNG import capacity being roughly equal to the amount of gas Russia previously supplied to Europe, there are constraints to the collective ability of these LNG terminals to meet European demand. The main such constraint is that existing European LNG terminals are mostly located in Western Europe while the dependence on Russian natural gas is greatest in Eastern Europe. The existing natural gas transmission network was configured to moving Russian gas from East-to-West and is not well suited to the West-to-East flow now being called of it. Pipeline capacity from the Iberian Peninsula, home to several large LNG terminals, to the rest of Europe is a particular issue. This saw authorities provide rapid planning approvals for new floating LNG receiving terminals including three in Germany, two in each of Italy and Greece, and one in each of the UK, France, and the Netherlands. One of these projects, the Wilhelmshaven floating LNG terminal, is already operating and took only 10 months to complete. The speed with which receiving infrastructure has been committed to and installed in Europe stands as an example of how quickly floating LNG projects can be brought into operation.

Another response strategy to reduce the impact of reduced gas flows to Eastern Europe from coastal LNG terminals has been to use existing transmission capacity to re-stock Europe's 6,400 PJ of UGS. UGS capacity can meet more than 25% of Europe's annual gas demand and provides a critical source of energy security to bridge the European winter. Designed to meet the large swings in seasonal gas demand between summer and winter, European UGS infrastructure has a combined maximum daily injection rate equivalent to 1% of total UGS storage capacity and a maximum daily withdrawal rate equal to 2% of UGS storage capacity. By comparison, before its working gas storage capacity was downgraded, NZ's only UGS facility at Ahuroa could store up to 9% of NZ's annual gas demand but its maximum rates of injection and withdrawal met just 0.4% of storage capacity.

Before the Ukraine crisis, some European UGS projects, such as the Rough UGS facility in the North Sea 29km off the coast of England, were mothballed or put on hold due to narrowing summer-winter arbitrages and the expectation that LNG imports could instead meet peak winter demand. As another response to the energy crisis, in November 2022 Rough's owner Centrica restarted the facility although only at 20% of its original capacity. Its reopening means that the UK is now able to store the equivalent of nine days of gas supply, up from six before its return. While a material increase, nine days is the lowest of any European country. Centrica is now seeking government support to expand Rough's handling capacity.

During 2022 LNG carriers were also reported to have been used as temporary gas storage by anchoring off the coast of receiving terminals ready to supply gas in case of a shortage or disruption onshore.

The compound benefit of sizeable LNG import receiving capacity and indigenous UGS capacity enabled Europe to manage the worst of its 2022-23 winter without any major disruptions to physical supply, albeit at the expense of record energy prices. This was also supported by market circumstances that worked to Europe's favour. This included China's zero-COVID policy which served to reduce AsiaPac LNG demand, making it less difficult than it would have been to divert cargoes contracted to Asia Pacific buyers to Europe instead. Weather was also a factor, with Europe experiencing record warm temperatures through much of its winter, reducing gas demand for space heating.

While market conditions are likely to see significant UGS storage retained to support the 2023-24 Northern winter, LNG supply is likely to be significantly tighter in the year ahead as Chinese industrial activity recovers as it moves on from its zero-COVID policy.

Indigenous LNG

LNG produced domestically from indigenous gas would be priced against the cost of alternative local market supply lines. This will vary depending on the particular application(s) for which indigenous LNG is applied but would ultimately reflect the cost componentry of competing energy sources including commodity, transmission, distribution and flexibility. We look at indigenous LNG options in Section 4.

3. NEW ZEALAND + LNG

PURPOSE

The purpose of this section is to identify and discuss potential NZ LNG import concepts and to analyse for their relative advantages and disadvantages. It also identifies potential domestic fuel applications that could be feasible if LNG was to become available in NZ.

3.1 NZ market requirements

The current security of supply outlook for gas in NZ can be split into two time horizons:

1. **Short-to-medium term**: Forecasts indicate a material supply shortfall against potential demand until at least 2022. While much of this shortfall will be absorbed by Methanex, supply constraints are likely to keep supply margins tight and prices cyclically high. The market impact of any shortage is likely to be most acutely felt in winter months when the risk of weak hydro sequence periods (and therefore higher marginal demand for additional generation gas) is greatest and coincides with higher seasonal residential and commercial demand with the colder weather. The key swing item is therefore generation gas demand. High wholesale electricity prices enable thermal generators to pay a higher per-unit cost for fuel. This has implications for unhedged or off-contract gas users, particularly large industrial users, which as was the case in 2020-21 found themselves competing with buyers able to secure strong generation netbacks while attempting to contract new gas.
2. **Medium-to-longer term**: The risk of shortage is expected to ease from 2023 due to a compound of new indigenous supply being brought to market and lower market demand, Methanex continues to idle its Waitara Valley plant and new renewable generation build displaces legacy thermal plant. The possible (albeit in our view unlikely) exit of Tiwai Point load in 2024-25 is a further aspect of specific and significant demand-side risk which would likely result in a sizeable one-off loss of demand and, with that, a material improvement in security margins. Due to the scale and load profile of thermal plant that would likely be retired following a Tiwai Point exit decision, the major beneficiaries would likely be Methanex and remaining thermal generators.

The timeframe uncertainties inherent within these horizon periods combined with an uncertain policy environment suggests a need for a solution that is flexible, reliable, scalable and non-permanent. LNG import using floating handling infrastructure aligns with each of these criteria and would integrate well with transmission and storage infrastructure that already operates in the market.

3.2 NZ LNG import concepts

In addition to filling the ‘gas gap’ imbalance brought about by any future shortfall in domestic supply against demand, LNG import could also provide hedge cover for a range of scheduled and unscheduled events and risks evident across the wider energy sector (Table 8).

The supply constraint that NZ faces is very small compared to most LNG importing countries. Of the 44 countries that imported LNG in 2021, only 11 imported less than 25 PJe pa, which is equivalent to less than 6-8 cargoes a year based on a standard LNG carrier of 120,000-170,000 m^3.

The relatively short time period across which LNG imports may be needed in NZ cuts directly across the investment case for constructing permanent land-based LNG terminal and jetty infrastructure. For this same reason, floating infrastructure concepts present a strong strategic and commercial fit with NZ’s market profile.

Another supporting factor is the proliferation of FSRU import projects being progressed on the Southeast coast of Australia, with five specific such projects across New South Wales, Victoria, and South Australia (Table 9). While currently only the Port Kembla project is known to have passed FID, others are receiving explicit support from state governments with a number appearing likely to proceed. Their arrivals would create a LNG trading sub-region in and around the Tasman Sea. As well as increasing the availability of shipping and cargoes, this could support more flexible LNG operations, such as partial cargo discharges or cargo delivery by LNG bunkering vessels, to service the NZ market. We have not accounted for such benefits in the concepts that we frame in this section, however the upside they potentially present is significant and could serve to materially reduce the lifecycle cost of LNG import into NZ.

Our survey of fleet availabilities suggests there are currently seven FSRUs not assigned to a LNG import project that could potentially serve as a NZ import facility. Some of these vessels currently operate as carrier vessels to ferry LNG between other load and discharge destinations and not using their regasification equipment. As NZ’s peak demand is countercyclical to the Northern Hemisphere’s, it is possible that a NZ-located FSRU could be released when not in use locally to service the short-term charter market during tight periods in the Northern Hemisphere winter. Recently charter rates for vessels into this market have reached NZ$400,000 per day.

Table 8: Domestic energy sector catalysts potentially supportive of LNG import

<table>
<tr><th colspan="2"></th><th colspan="2">POTENTIAL FUEL CATALYST</th></tr>
<tr><th colspan="2"></th><th>Renewable</th><th>Thermal</th></tr>
<tr><td>UPSTREAM</td><td>Fuel-specific</td><td>• Dry hydro sequence
• Unfavourable (for hydro and/or wind) seasonal climate outlook
• Major scheduled hydro and/or geothermal production asset outages / turn-downs
• Major unscheduled hydro and/or geothermal production asset outages / turn-downs</td><td>• Major scheduled gas or coal production asset outages / turn-downs
• Major unscheduled gas or coal production asset outages / turn-downs
• Deliverability decline(s) not sufficiently offset by new indigenous supply</td></tr>
<tr><td rowspan="2">MIDSTREAM</td><td>Fuel-specific</td><td>• Unexpected transmission constraints and/or outages reducing export capacity from major South Island hydro plant</td><td>• Scheduled or unscheduled outages / turn-downs of Ahuroa UGS facility
• Sharp increase in LNG-equivalent feed-in cost of competing fuel coal vs indigenous gas</td></tr>
<tr><td>Integrated</td><td colspan="2">• Major scheduled electricity and/or gas transmission outage(s)
• Major unscheduled electricity and/or gas transmission outage(s)</td></tr>
<tr><td>DOWNSTREAM</td><td>Integrated</td><td colspan="2">• High electricity demand growth and/or legacy load retention (eg Tiwai Point) ahead of arrival of new generation build
• High gas demand growth (eg on North Island industrial coal switching) and/or legacy load retention (eg Rankines retained on gas-rich burn)</td></tr>
</table>

Source: Enerlytica

Table 9: East Coast Australia LNG FSRU projects

Project	Owner	Capacity	Commercial model	Expected start-up	Projected cost
Port Kembla, NSW	AIE / Squadron Energy	100 PJ pa	Merchant	Q4, 2023	A$250m capex excluding FSRU charter
Outer Harbour, SA	Venice Energy / Integrated Global Partners	110 PJ pa	Contracted tolling	2026	A$200m capex excluding FSRU charter
Newcastle Gasdock, NSW	EPIK	300 PJ pa	Contracted tolling	Terminated due to LNG price rises	A$500-600m including FSRU build
Geelong, VIC	Viva Energy	80-140 PJ pa	Tolling and Merchant	2025	A$210m excluding FSRU charter
Avalon, VIC	Vopak	200+ PJ pa	Open access tolling	2026	Unknown

Source: public information, Enerlytica

Receiving infrastructure concepts

We have identified four import concept locations (Figure 25) where a FSU, FRU and/or FSRU could moor and connect to the existing high-pressure gas transmission network. They are:

1. **Marsden Point**: FSU and FRU moor at the existing jetty at Marsden Point near Whangarei.
2. **Port Taranaki**: FSRU moors at Port Taranaki in New Plymouth.
3. **Maui-A**: FSRU moors as a tie-in to the offshore Maui-A wellhead platform located 35km off the Taranaki coast.
4. **South Taranaki Bight**: FSRU moors in open water and connects via a new seabed pipeline to the existing Southern high-pressure pipeline.

Each of the concept sites we have scoped present very different development and operating profiles with large variations in key technical characteristics and value drivers such as capital costs, gas feed-in capacity, existing infrastructure access, ease of LNG transfer operations and mooring system design.

Figure 26 summarises the specific infrastructure and integration features involved with each of the options we isolate.

In the section that follows we identify and discuss the technical componentry that would likely be required of each concept and estimate for the capital and operating costs of each site against a common set of economic screening assumptions.

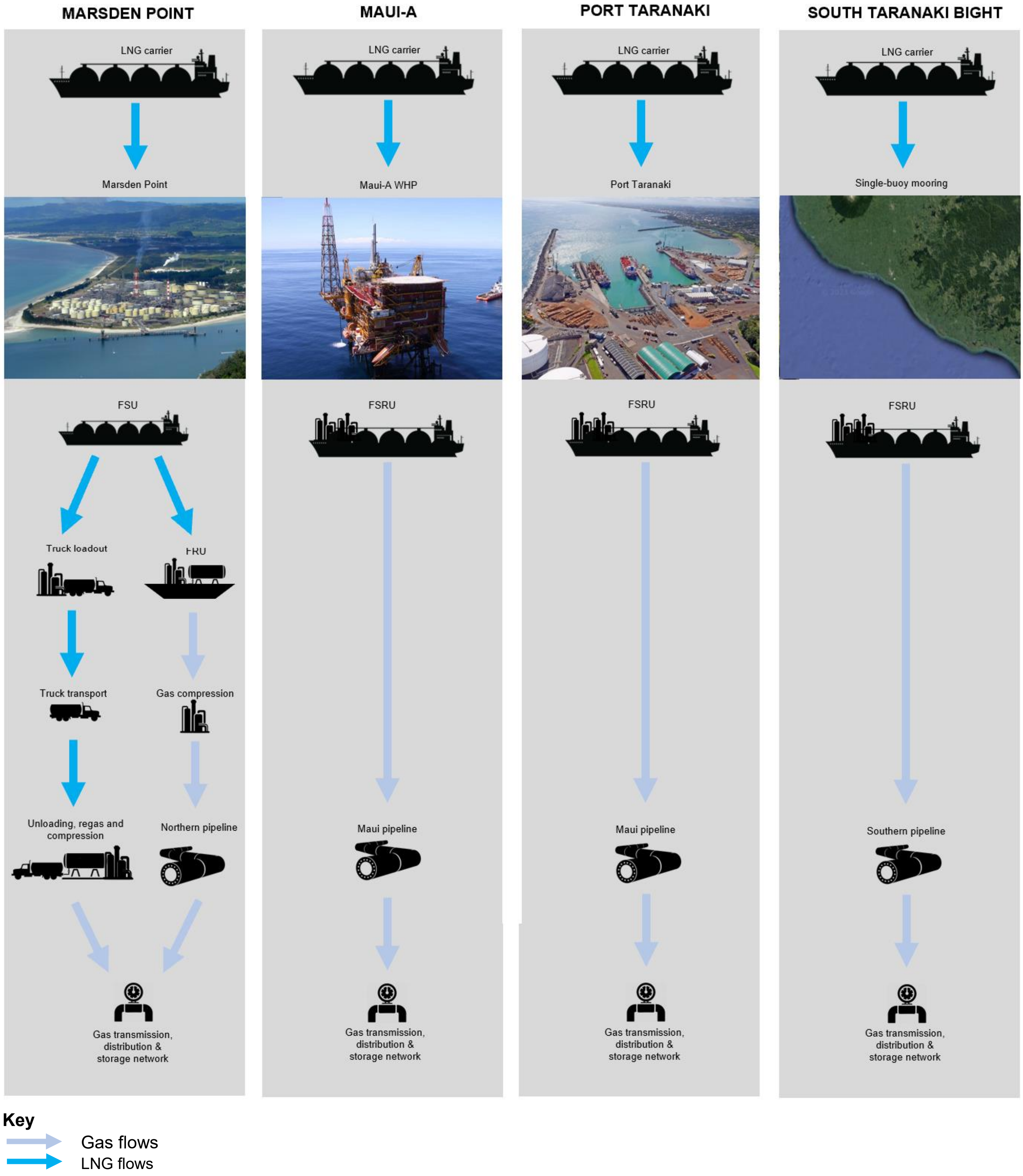
Important to note is that the list of site concepts we have identified is not exhaustive and there are likely to be other site options worth considering. This is particularly the case with offshore settings where there may be opportunities to locate a FSRU as standalone operation in calmer waters than the relatively harsh sea state that Maui-A presents and potentially even calmer than that found in the South Taranaki Bight.

Also important to note in considering these concepts is that our analysis is based on desktop assessments of the infrastructure that would likely be required at each site against market benchmarks for the approximate current cost of the infrastructure we assess as required. The conclusions of our analysis should therefore be considered as indicative. Full feasibility assessments including detailed costings would need to be undertaken to validate the costings for any option.

Figure 25: NZ LNG import concept site locations

Source: First Gas, Enerlytica

Figure 26: NZ import LNG receiving infrastructure concepts



Source: Enerlytica

Marsden Point

Marsden Point, located just south of Whangarei, has an existing 300m long jetty in water 14.7m deep which could be readily modified to accommodate LNG handling infrastructure. The waterway that encompasses the jetty is sufficiently large to house a permanently moored FSU and FRU (explained below) as well as LNG carriers that could come alongside to carry out ship-to-ship LNG transfer. A significant advantage of the site is that the jetty is sited in a waterway that is sheltered from prevailing swells, allowing high accessibility which is important to prevent cargo discharge delays that can lead to buyers suffering demurrage costs. While other vessel traffic in the waterway is significant given the site's proximity to Northport and its own oil product cargo operations, harbour masters should be able to accommodate what would likely only represent a small number of additional ship movements in any given year.

A key potential advantage of the Marsden Point option is that in early 2021 the site's owner, Refining NZ (now Channel Infrastructure), secured resource consents to support site operations for a further 35 years. Whether LNG handling could fit inside the consent envelope would need to be tested against infrastructure requirements. For example, traditional FSRU operating practices such as the use of seawater as a source of heat for LNG vaporisation could need to be modified to navigate environmental permits. If so, development lead times could be very much faster than would be the case for other options where consenting and approval processes could require significant additional time to manage and resolve.

A key disadvantage of the site is that the gas pipeline that connects Marsden Point with Auckland has very limited capacity. The six-inch pipeline that originates from the Henderson compressor station currently supports a maximum flow of only 20 TJ/day. Adding compression along the pipeline could increase handling to a maximum of 30 TJ/day at a cost we estimate of up to $21m.

An option to supplement the pipeline and provide the additional 145 TJ/day of flex that could be required by thermal generators could be to transport LNG by road to a receipt point beyond the pipeline bottleneck. There the trucked LNG could be discharged into a vaporiser and compressor system to regasify and pressurise received LNG to enable it to be fed into the network. The truck module would in effect serve as a virtual pipeline to carry LNG from Marsden Point to a receipt and/or vaporisation facility, in much the same way as is already done with domestic market handling of LPG.

Trucking would involve carrying cryogenic ISO containers. The payload of each truck movement would be subject to regulatory clearances and whether one or two containers could be carried on each journey. A single container would likely approximate a 20-tonne payload (broadly equivalent in scale to a LPG road bullet, and carry 0.9 TJe of gas)

Box 6: Rapid LNG import project using FSRU

In 2013, Egypt was facing an energy supply crisis. Having previously exported natural gas in both gaseous and LNG form, an increase in energy demand from a rapidly growing population and a fall in production after the Arab Spring disrupted E&P projects led to a gas shortage. Needing to import gas quickly to meet demand, EGAS, the national gas company, issued tenders to supply it with FSRUs for a period of five years. The first tender was issued in October 2013, with the new-build Hoegh Gallant FSRU entering operation just 18 months later. The charter was for a period of five years, ending in April 2020.

In a second tender round in July 2015, the newly built BW Singapore FSRU commenced operations just five months after winning the tender. The BW Singapore has storage capacity of 170,000m^3, a peak regas capacity of 750 mmscf/day (800 TJ/day) and maximum handling capacity of 5.7 mtpa (313 PJe pa). It was chartered primarily to supply gas to the local fertiliser industry and at peak operation received a cargo every 5-6 days.

The projects were able to be delivered quickly due to a combination of suitable existing jetty and gas infrastructure in Egypt, the efficiency of construction at specialised shipyards in China and South Korea and FSRU availability.

By 2019, following a period of revived exploration and new gas discoveries, LNG imports were no longer required and the Hoegh Gallant was released from its time charter almost two years early and chartered to a third party, with EGAS compensating for the difference between the original FSRU contract and the new time charter for the remaining two years of the original charter. EGAS has however retained the BW Singapore to support security of supply.

Hoegh Gallant & BW Singapore receiving LNG cargo

while two containers would enable 40 tonnes (1.8 TJe of gas) to be moved. By comparison, a single 30 tonne truck movement of coal carries 660 GJe of gas.

There are a range of potential sites that could host the inland regasification facility, the closest of which is likely to be the Henderson compression station, 150km from Marsden Point. Other potentially feasible sites include the Glenbrook steel mill and the Te Rapa dairy factory, each of which could provide waste heat to the regasification process, reducing costs. The owners of these sites may also be attracted by the potential flexibility and security of supply benefits that onsite storage of LNG could provide as well as its potential to support other high-horsepower applications onsite, such as trucking and peak shaving. Any receiving site would need to install or upgrade gas compression equipment to be able to inject gas into the network. The combined capex for truck loading, receiving, regasifying, and compression facilities to deliver up to 145 TJ/day would we estimate range between $102-142m, with the range reflecting uncertainties surrounding regas and compression requirements.

To deliver the additional 145 TJ/day of gas that the Northern pipeline cannot provide under a peak LNG demand scenario, we estimate that between 88 and 177 truck shipments per day would be required at peak, depending on whether one or two ISO containers could be carried per journey.

Although we do not explicitly account for it in our scoping, a potentially attractive further option with the Marsden Point concept could be to add a floating gas-fired generation module (known as a power barge or powership) to operate alongside the FSU and FRU. This would reduce some of the need to truck product South by road and the addition of fast-start peaking generation could present a good fit with the electricity market, particularly given the rapid expected growth in intermittent generation (solar and wind in particular) in the Northland region. Modern power barges also commonly include grid-scale batteries integrated onboard which could add to the attractiveness of the option.

Given the pipeline constraints that accompany the site, it would be inefficient to charter a standard FSRU designed to deliver much larger regas volumes. It would instead be more cost effective to charter an older LNG carrier which can be used as an FSU and connect it to a smaller FRU. Such vessels have older propulsion and container technologies and are less in demand than more modern vessels, providing cheaper lease costs. The FSU would receive LNG from carrier vessels via ship-to-ship transfer while at the jetty and could then pass this, via cryogenic piping, to the FRU and truck loading station. The FRU, which would regas the 30 TJ/day of LNG delivered into the Northern pipeline, would most likely be purpose built on a small barge. As the Benoa case (Box 3) highlights, vessels of this type can be delivered within a year of being ordered.

While truck loading provides a workaround solution to constrained send-out capacity, tolerances for truck movement numbers could limit the volume of LNG that could be moved. The gas send-out rate from Marsden Point is therefore more physically constrained than at any of the other three options we frame. This is less of an issue longer-term as a likely terminal decline in gas demand materialises. Should the facility remain, the investment in LNG vaporisers could also seed a future peak shaving facility which could become viable in the event of gas oversupply.

Port Taranaki

Port Taranaki, similarly to Marsden Point, offers a sheltered harbour with pipeline access and would be able to accommodate a permanently moored FSRU. A strong advantage is proximity to two existing pipelines, one 8-inch and one 20-inch, which could support a feed-in rate of potentially as high as 500 TJ/day.

A key disadvantage however is that none of the existing jetties are large enough to be able to simultaneously accommodate a standard size FSRU *and* a standard LNG carrier to berth and discharge its cargo alongside. The existing jetties are also very close to other cargo handling operations at the port, posing a potential health and safety hazard if LNG operations were to be added. A feasible option to manage these constraints could be to modify the port to be able to house the FSRU and LNG cargo vessel on a new jetty within the breakwater. We estimate this work would require a total capex outlay of between $140m (low case) and $210m (high case).

Even with a new jetty that could accommodate a standard FSRU and LNG cargo vessel, other port operations would likely still be disrupted during discharge operations. Negotiations among port users would be required to establish rights of way and priority access. Similar issues at Gladstone in Australia, a much larger harbour and waterway and home to three very large LNG export terminals and a coal loading port, saw existing coal operations given right of way over LNG loading.

A procedure that could reduce the potential disruption to other port operations and even allow for the use of existing jetty infrastructure (if deemed safe) could be to undertake LNG cargo transfer operations beyond the breakwater (Box 9). This could be done via ship-to-ship transfer when sufficiently calm conditions are present outside of the harbour. Ship captains would ultimately have decision rights over the acceptability of sea and weather conditions. It is even feasible for the FSRU itself to collect cargoes directly, although this is not yet an established import model and would only yield material price benefits in a very tight shipping market. While technically feasible, neither of these options are ideal as they would necessarily involve a period of temporary separation of the gas market from the LNG backstop. This period could be between 2-4 weeks in the case of a FSRU collecting its own cargo.

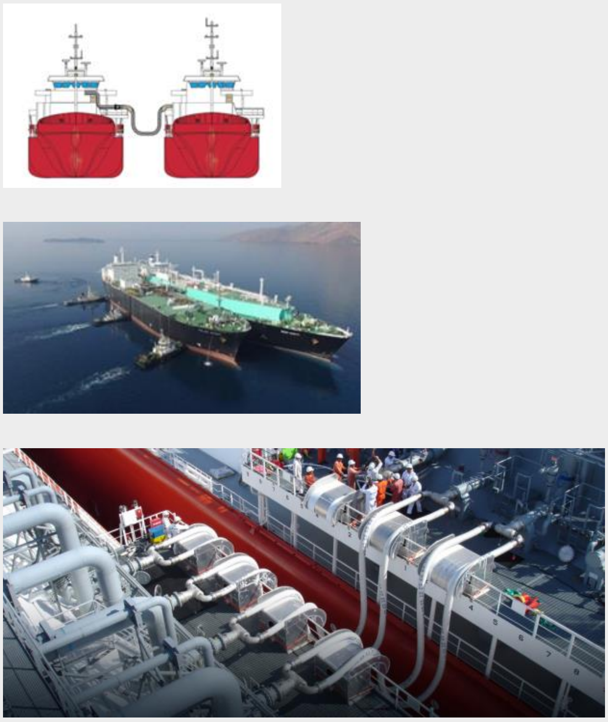
Box 7: Open-sea LNG ship to ship transfers

While the ship-to-ship transfer of LNG from a carrier to a FSRU is a routine operation when conducted at port, the transfer of LNG between carriers at sea is much less common and is normally limited to sheltered waters at convenient points on major shipping routes.

Subic Bay in the Philippines is such an example as it sits enroute towards four major LNG importing countries (China, Taiwan, South Korea, Japan), allowing a carrier to break bulk, splitting its cargo among several ships to serve a number of customers.

Open ocean ship-to-ship transfers are rare but have been conducted. Successful operations rely on the capability and experience of vessel captains, available tug support, prevailing sea states, and how comfortable the vessel owners are with conducting such operations. This is however an area of ongoing progress and improvement with new design features continuing to be brought forward to enable ship to ship operations in a wider range of conditions.

Flexible hose transfer systems



Source: Excelerate Energy

Regardless of how LNG is transferred to the FSRU, the ability to release a modern FSRU from its moorings provides substantial additional physical and commercial flexibility. For example, should the FSRU be underutilised in NZ it could be released to the sub-charter market. Should this occur during the NZ summer (the northern hemisphere winter), a significant portion of the head charter costs could potentially be recovered. Also notable is that any investment in port infrastructure to accommodate a FSRU would likely have benefits that extend beyond the expected lifetime of any LNG import project. For example, investment in dredging and a new jetty could enable a port to receive a wider variety of cargo handling operations with larger vessels.

Maui-A wellhead platform tie-in

Unlike the Marsden Point and Port Taranaki options, this concept is not based at any existing port. Instead, it involves connecting a FSRU by its bow to a new single point mooring system to tie-in to the Maui-A wellhead platform.

Regasified LNG would travel via hoses through the mooring system and connect to the existing umbilical pipeline for relay onshore to the Maui production station and from there into the high-pressure gas network. The single point mooring system would allow the FSRU and discharging vessel to weathervane in the open sea, similar to how the FSRU Lampung (Box 8) off the coast of Sumatra in Indonesia operates and how FPSOs have previously operated in NZ waters.

Based on analogues including the FSRU Toscana and FSRU Lampung, such a mooring system along with vessel modifications could we estimate cost between $208m and $310m. The large range reflects the scope of engineering complexity that may be required to design and build a system to meet Tasman Sea conditions. The FSRU, likely an older, cheaper Moss type vessel more suited to handling potential sloshing of its LNG cargo, would also need to be modified to connect to the single point mooring system since they are typically designed to sit alongside a jetty and connect to other vessels on their broadsides.

Notable is that we expect that the $624m upper bound capital cost estimate of the Maui-A option is likely to approach the cost of building a permanent receiving terminal onshore with a broadly similar handling capacity.

This side-by-side form of ship-to-ship transfer is not ideal for the heavy sea-state conditions during the Southern Hemisphere winter and is distinct from the bow-to-stern method that FPSOs transferring oil and condensate have operated under in NZ waters. Cargo discharge disruption due to weather and/or sea state would be a material risk under this scenario which could see NZ LNG buyers potentially liable for demurrage costs, effectively increasing the cost of a cargo.

Box 8: Open-sea FSRU mooring systems

The Toscana is moored 22km off the coast of Livorno, Italy, and was developed by converting an existing LNG carrier, the 138,000m^3 Golar Frost, between 2011 and 2013. As well as housing regas facilities, the vessel was equipped with an external column turret mooring system welded to the bow and originally designed for FPSOs. This connects to the sea floor through six equally spaced chains and embedded anchors which allows for ship-to-ship transfers in sea of up to 2.5 metres. The ship conversion and turret system is estimated to have cost US$500m (NZ$710m) and is considered to be one of if not the most expensive FSRU conversion projects ever completed.

FSRU Toscana receiving LNG cargo

Source: OLT Offshore LNG Toscana

Another open sea project is the FSRU Lampung, moored 6km off the coast of Southern Sumatra. Operated by Hoegh, the vessel was built for purpose at a cost of US$300m (NZ$430m) and received its first cargo in 2014, a year after the Toscana. It uses a tower yoke mooring system that alone is estimated to have cost US$100m (NZ$142m) and was designed to accommodate sea states of up to 2.8 metres. It is not known if this wave height rating is also its operational limit for ship-to-ship transfers but the area is likely more sheltered from significant swells than the Toscana.

FSRU Lampung receiving LNG cargo

Source: PGN LNG

Another drawback is that the process of disconnecting and reconnecting to the mooring system would not be as straightforward as connecting to a jetty or mooring system within the confines of a harbour. This would restrict sub-chartering options for the FSRU for carrier operations or enabling ship-to-ship operations in more favourable waters.

This scenario would also require access to the Maui-A platform and pipeline to be negotiated with Maui field owner and operator OMV. The potential terms and cost of this access is highly uncertain but would represent a significant additional complexity of pursuing the option. The existing pipeline would however be able to accommodate above the 500 TJ/day capacity of most FSRUs and thereby the 175 TJ/day potential required swing of thermal generation.

South Taranaki Bight

The South Taranaki Bight option would see a FSRU connected to an offshore mooring system off the Taranaki south coast. The primary reason for investigating this location is that the sea state in the region is considerably calmer than other areas including around Maui-A, being sheltered from most swell directions apart from those from the W-NW directions. If a FSRU was to be moored in this area it would be much more likely that it could look to a fixed, spread mooring system which would be significantly less expensive than a single-point option. We estimate a cost range for a spread mooring system of between $104m and $187m.

A spread mooring system would likely be located a sufficient distance offshore so as not to materially obstruct ocean views. As there would be no existing subsea natural gas pipelines or other infrastructure in the area, a new subsea pipeline to the mooring location would need to be laid and connected to the onshore high pressure gas pipeline network, which lies near the coast. Based on international cost benchmarks, we estimate the cost of the pipeline leg at between $59m and $88m.

While a South Taranaki Bight option is likely to be a less expensive alternative to the Maui-A option and be less likely to incur demurrage charges, it would likely be restricted to similar limitations surrounding the disconnection and reconnection of a FSRU. Because of this, in our analysis of the South Taranaki Bight option we do not assume any sub-lease of the FSRU.

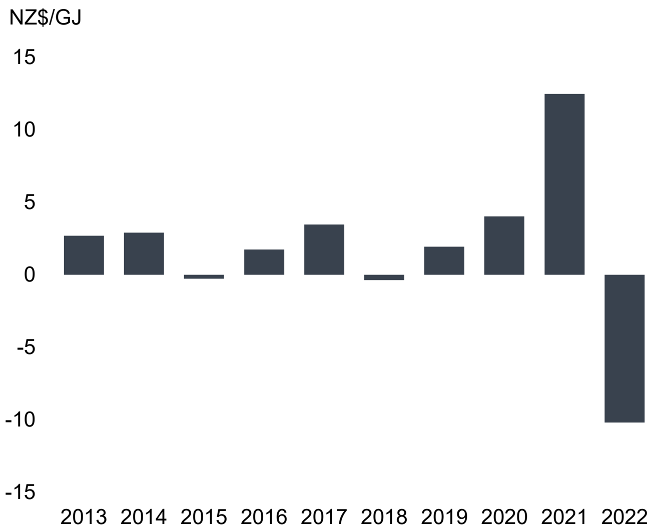
3.3 LNG procurement

The relatively high current extent of indigenous supply and demand outlook uncertainty means that the potential requirement for LNG import across years and within years is also uncertain. There are many potential catalysts and events that could contribute to a need for imports (Table 8) including gas deliverability decline, asset outages, low hydro storage levels, an unfavourable seasonal climate outlook and low gas system inventories.

This uncertainty would support a LNG buying strategy based on procuring spot market cargoes rather than committing to long term take-or-pay agreements. While this does mean that pricing for LNG would be linked to shorter-term Asia-Pacific market trends rather than fixed at a single price, this is no different to what already occurs with most other NZ fuel imports including crude oil, refined oil, LPG and coal. As there will be some visibility towards forward LNG demand (particularly in the case of boil-off, discussed below) buyers would still hold some ability to hedge specific parts of the delivered price including each of the commodity and foreign exchange components.

As NZ demand for LNG cargoes would be strongest during the Northern Hemisphere summer, importers would likely be able to acquire spot cargoes during what has historically been a lower price period. Pricing data for the past 10 years shows that Northern summer prices typically settle on average 20% below their preceding winter equivalents (Figure 27). Notable however is that the disruption brought about by the Russia-Ukraine conflict has disrupted this trend with a likely increase in demand during the Northern summer to support off-season restocking of gas storage.

Figure 27: Northern hemisphere winter vs summer price differences for Asian spot LNG



Source: Refinitiv, Enerlytica

Cargo lead times

The LNG spot market is typically able to meet orders with a 6-8 week lead time. That is to say that a buyer in NZ should aim to procure a cargo at least 6-8 weeks in advance of when it is assessed as needed, but preferably further ahead. While the spot market can meet demand at shorter notice, these cargoes would typically be considered distressed acquisitions and command a higher price to incentivise LNG sellers to break from their existing shipping and sales positions.

A 6-8 week lead time would in any case be a good fit with decision horizons involved with most of the key factors that would contribute to a LNG import decision into NZ, in particular those of hydrological cycles, demand seasonality, gas deliverability and scheduled plant outages and/or turn-downs.

Boil-off gas management

In a situation where LNG import infrastructure was installed and maintained to support security of supply but developments in domestic market supply and demand made the import of product unnecessary, it may still be necessary to import a cargo every 1-2 years. This is because of the "ageing" or "weathering" of LNG stored in the tanks of the FSRU as it boils-off. If not properly managed, this can lead to the LNG stored on the ship turning off-spec and becoming unsuitable for injection into the gas system. If this occurs, fresh LNG would need to be added to either completely replenish the LNG in storage or to "spike" it to return it to on-spec.

How much of an issue LNG weathering could become relies in part on from where LNG is sourced. LNG from Eastern Australia is likely to pose less of an issue due to its "lean" (high purity of methane) nature although vessel owners may still request a minimum throughput to keep onboard facilities tested and in working order.

The preferred way to manage boil-off gas would be to bleed it through the FSRU's regasification module and feed it into the domestic gas system. The feed-in rate of this could be as low as 5 TJ/day on a full 4.2 PJ cargo with ~1.5 PJ bled in the first year.

While it could be argued that a minimal LNG requirement could facilitate a small longer-term take-or-pay delivery contract for cargoes targeting delivery during the southern hemisphere winter, a small contract is unlikely to yield a significant price benefit. If a small long-term take or pay contract was negotiated but ultimately was not required due to improved domestic market conditions, the cargoes could be on-sold into the spot market.

3.4 Option economics

To compare the economics of the four FSRU-based design concepts we have opted to apply both common and concept-specific assumptions:

1. **Common**: FSRU lease costs, non-FSRU opex, WACC and corporate tax.
2. **Site-specific**: Estimates for location-specific capital and operating cost items including vessel mooring systems, jetty modifications, pipework, dredging and demurrage.

Common assumptions

The assumptions that are shared across the four concepts are summarised in Table 10.

Table 10: FSRU lease & transfer cost assumptions

Component	Unit	Low	High
Modern FSRU head lease	US$k/day	150	200
Modern FSRU sub-lease	US$k/day	57	220
Modern FSRU sub-lease	Days	120	120
Demurrage	US$k/day	500	500

Source: Enerlytica

In our calculations we have assumed a NZD/USD of 0.65 and applied the current NZ corporate tax rate of 28%. To proxy for a required return on capital (being the investment required of project developers in handling infrastructure) we have applied a 10% nominal post-tax WACC. Economics are presented on an ungeared basis and therefore absent of value uplift that would normally be expected if a more efficient financing structure was to be applied.

Site-specific assumptions

The assumptions that are specific to the four design concepts are summarised in Table 11.

Table 11: NZ LNG option infrastructure profiles

Component	Marsden Point	Maui-A	Port Taranaki	South Taranaki Bight
Storage	FSU	FSRU	FSRU	FSRU
Regasification	FRU			
Mooring	Jetty	WHP tie-in	Jetty	Ocean
Export max TJ/day	30	500	500	150
Truck loadout	Yes	No	No	No
Remote vaporiser	Yes	No	No	No

Source: Enerlytica

Option benchmarking

To compare the attractiveness of each of the four concepts we have applied a traffic light system to score the sites on the basis of cost, ease of execution and ease of operation (Table 12). A green shading reflects a positive assessment, red reflects a negative assessment, with yellow as neutral.

The comparison highlights the significant cost and operating challenges of developing a project offshore at Maui-A compared to near-shore options at Marsden Point, Port Taranaki and the South Taranaki Bight. Although Maui-A offers the significant benefit of not interfering with shipping traffic and potentially smoother regulatory and permitting processes, the sea state is likely to require a highly bespoke mooring system and the commercials of being able to connect to the platform are also likely to be expensive and complicated.

The lack of export pipeline capacity at Marsden Point requires significant additional capex to enable road transfer of LNG to increase feed-in capacity. While the pipeline+road solution for Marsden Point would allow gas flows up to 175 TJ/day, 500 TJ/day send-out capacities are already available at Port Taranaki and Maui-A, enabling a single LNG cargo to be delivered into the grid in as little as 9 days if required. We have sized the Southern Taranaki Bight option to present a gas send-out capacity of 150 TJ/day.

The additional capacity and flexibility any of the sites would provide could integrate favourably with existing infrastructure, including the Ahuroa UGS facility.

Port Taranaki offers the strongest balance of cost, operating flexibility, and ease of execution benefits although its feasibility may be constrained by permitting processes and port access arrangements.

3.5 Commercial model

Commercial models for FSRU (including FSU+FRU) projects generally (but not exclusively) fall into one of three types: Integrated, Tolling, and Merchant (Figure 28).

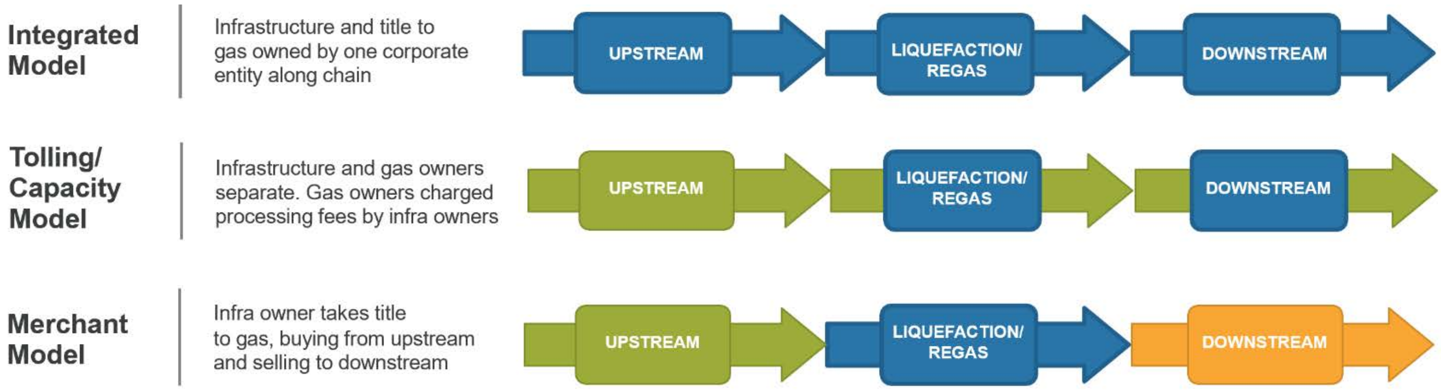
Each model assigns risk between the owners and customers of the LNG import facility differently, although ultimately the costs of building and maintaining the infrastructure required is borne by its users. Which model is preferred and how its associated operating agreements are drafted will depend on the number of parties interested in subscribing to import gas and their respective commodity and capacity requirements. Also relevant are skills in commodity trading, financial strength, ancillary gas businesses, as well as any infrastructure and market limitations on LNG imports.

Table 12: Benchmarking of LNG import options

		MARSDEN POINT		MAUI-A		PORT TARANAKI		SOUTHERN BIGHT	
		Best Case	Worst Case	Best Case	Worst Case	Best Case	Worst Case	Best Case	Worst Case
Capex									
FSRU integration	NZ$m	77	90	188	270	-	-	138	195
Dredging, jetty, mooring & pipework	NZ$m	57	86	238	354	140	210	190	317
Regas & network delivery	NZ$m	116	162	-	-	-	-	-	-
TOTAL	NZ$m	**250**	**338**	**426**	**624**	**140**	**210**	**328**	**511**
CRF fee									
2030 end date	NZ$m	63	103	131	242	35	64	100	199
2040 end date	NZ$m	33	48	61	95	19	30	47	78
2050 end date	NZ$m	28	39	50	76	16	24	38	62
Fixed opex fee									
FSRU	NZ$m	13	15	25	37	84	122	23	31
Port, mooring, jetty & pipework	NZ$m	5	7	63	107	21	32	29	48
Regas & network delivery	NZ$m	3	4	-	-	0	0	0	0
TOTAL	NZ$m	**21**	**26**	**88**	**144**	**105**	**154**	**51**	**79**
Variable opex fees $/GJ									
FSRU & regas fees	NZ$/GJ	0.91	1.27	1.08	1.81	0.99	1.54	0.99	1.53
Network distribution fees	NZ$/GJ	2.10	3.41	0.64	1.87	0.64	1.87	0.64	1.87
Total	NZ$/GJ	**3.00**	**4.67**	**1.72**	**3.68**	**1.63**	**3.41**	**1.63**	**3.40**
International LNG price	NZ$/GJ	42.71	60.20	42.71	60.20	42.71	60.20	42.71	60.20
Post import project price	NZ$/GJ	**45.72**	**64.87**	**44.43**	**63.88**	**44.34**	**63.61**	**44.34**	**63.60**
Traffic light criteria									
Construction lead time	years	1	2	2	3	1	2	2	3
Existing safe harbour & mooring?		Yes		No		Requires modifications		No	
Sufficient pipeline capacity to rest of NI?		No		Yes		Yes		No	
Likelihood of ship traffic interference?		Low		Low		High		Low	
Regulatory & permitting complexity?		Medium		Low		High		Medium	
Est total cargo handling capacity	PJ pa	57		164		164		49	
Daily gas send-out capacity	TJ/ay	175		500		500		150	
Capex per cargo handling capacity	$m/PJ	1.4	1.9	0.9	1.2	0.3	0.4	2.2	3.4
Total Fees									
2030 close	NZ$m	83	130	219	386	141	218	152	278
2040 close	NZ$m	54	74	149	239	124	183	98	157
2050 close	NZ$m	48	65	138	220	121	178	90	141
Fee per GJ.MDQ Gas									
2030 close	NZ$/GJ.MDQ	477	740	438	772	281	436	1,011	1,852
2040 close	NZ$/GJ.MDQ	308	424	298	478	248	367	655	1,046
2050 close	NZ$/GJ.MDQ	277	374	275	440	242	356	597	942
Fee per GWh.MDQ Electricity									
2030 close	NZ$m/GWh.MDQ	4.2	6.6	3.9	6.9	2.5	3.9	9.0	16.5
2040 close	NZ$m/GWh.MDQ	2.7	3.8	2.7	4.3	2.2	3.3	5.8	9.3
2050 close	NZ$m/GWh.MDQ	2.5	3.3	2.5	3.9	2.2	3.2	5.3	8.4

Source: Enerlytica

Figure 28: Potential commercial operating models



Source: Enerlytica

For example, a strict Merchant commercial model sees the FSRU project owner assume significant risk by only receiving revenue when the vessel and infrastructure is being used to import LNG. When this demand arises, the FSRU project owner takes commodity risk, procuring LNG itself and earning a margin by selling the gas to domestic wholesale buyers. Such a model works best when consistently high import volumes are required and when LNG can be acquired at a discount to local gas prices.

Compared to other regions, the low relative quantity and high relative variability of import volumes that NZ would likely require would we expect be of very low interest to potential developers and as a result be unlikely to deliver the outcome surety a strict Merchant model would typically require.

To bridge the incentives of users that seek an option to import gas but do not know the volumes they will require in any given year, and investors that require reliability of revenues and returns, Integrated and Tolling models are likely to provide the strongest fit to NZ's market characteristics. Under these, FSRU opex and capex recoveries would be funded by downstream users of the facility. This would effectively see users pay a fixed premium for an open-ended gas import call option with the strike price of the gas itself determined by international LNG markets.

Parties seeking import capacity have two broad structuring options. They can either assume the risk of owning the project and take the assets onto their balance sheet(s), or they can let another party do so to whom they would contract to pay a yearly fee to secure LNG import capacity. The former case is described as an Integrated or Semi-Integrated commercial model while the latter would be considered as a Tolling or Capacity fee-based model.

Under a strict Integrated model, the owner and user of the FSRU and imported LNG are legally one and the same. Examples of this are LNG-to-Power projects where the thermal generation asset must generate enough revenue to cover the FSRU and LNG import costs.

Under a Tolling or Capacity fee-based model, the owner and user of the project are legally separate with users often acting to underwrite a project by paying the owner a guaranteed fee over a number of years to cover costs and deliver a fixed rate of return on investment. In exchange, users receive a share of available capacity rights.

Mixing these models is known as Semi-Integrated structure because, even though the project owners and users may be legally separate, they have the same parent. For example, a FSRU project owner could simultaneously hold interest in gas sales, distribution, or consuming businesses upstream or downstream of the project which would pay tolling fees to the project.

New Zealand model

The local parties likely to be the most interested in holding a LNG import call option would we expect be:

- **Major thermal generators** Genesis Energy, Contact Energy, and Nova Energy. Interest from each is likely to vary given their different business and fuel models and strategic directions.
- **Industrial gas consumers** with lower gas demand potential but a strong imperative to secure gas. While likely too small individually to underwrite an LNG import project, users could consolidate their buying power to create a buying consortium.
- **Upstream and midstream asset owners** that face delivery risk pooled into a handful of producing assets and pipelines which could view LNG as a means to provide cover for supply disruptions to indigenous gas production. Also, while we think it unlikely that Methanex would present any interest in directly underwriting import facilities, participation at some indirect commercial level is not out of the question.

LNG could serve as a potential short-term stopgap to keep plants running at higher run-rates should gas suppliers not themselves show interest in LNG import to support indigenous supply.

Given the range of potential users, we expect that a strict Integrated project structure is unlikely to be preferred. This is not to eliminate the possibility however as it is feasible that outcomes of strategic review processes by thermal generators could in time justify consideration of an Integrated structure. For example it is conceivable that a single generator could own a LNG import project outright as part of a wider portfolio that includes thermal generation assets, rights to onshore gas storage and upstream asset interests.

If coordination among individual asset holders does not result in an Integrated structure, Semi-Integrated or Tolling models are more likely. A Semi-Integrated structure could be structured as an incorporated joint venture, allowing multiple interested parties to potentially participate.

For any commercial model that involves multiple FSRU capacity holders the commercial agreements surrounding import and send-out operations would have to account for the fact that a standard FSRU will only be able to store one cargo delivery of LNG at any one time. This makes coordination around LNG purchases and gas send-out a key consideration as it would not be possible to let each capacity holder purchase and store standalone cargoes simultaneously as can be done at some land-based terminals which provide storage tanks dedicated to individual customers.

To manage this, capacity holders could pool together as a consortium to import cargoes under a joint operating agreement with their percentage of capacity entitling them to an equivalent percentage of LNG volumes discharged into the FSRU. The flexibility to abstain or encourage such joint purchases would be enabled through “tag along”, “drag along”, “pre-emption” and “sole risk” rights negotiated into the operating agreement. Such a consortium would also make the purchasing of LNG from the spot market more efficient by preventing the duplication of each party negotiating separate Master Sale Agreements (MSAs) with LNG sellers. Cooperation of this type already exists in several energy market settings in NZ including in the handling of LPG, crude oil and refined oil.

3.6 Landed indigenous-equivalent pricing

Estimating for the indigenous-equivalent price of imported product is a central consideration of the economics of any LNG import options. Important within this however is distinguishing between the cost of acquiring and/or maintaining the option to import LNG and the cost of procuring physical LNG.

Capacity costs

An LNG import facility allows capacity holders with uncertain import requirements to access international LNG markets, purchase cargoes off the spot market and import as much gas as they might require up to the physical limits of the infrastructure. It also allows its capacity holders to feed that gas into the grid from LNG storage tanks at highly flexible rates as and when required. Payments made by capacity holders to cover the fixed operating costs of an import facility and provide the import project owners a fixed rate of return on capex therefore effectively represents a premium paid for a flexible call option on gas.

Our analysis, summarised in Table 12, indicates that the premium for this call option would, for an end date of 2030, range between $83-130m pa for Marsden Point and $141-218m pa for Port Taranaki, not including potential FSRU sub-chartering recoveries. By sub-chartering the FSRU or FSU during periods where it is not required, we estimate there is the potential to recover as much as $10-40m pa of this cost. For Maui-A the premium would range between $219-386m pa and between $152-278m pa for South Taranaki Bight. When extending the end date to 2050, the option premiums would reduce to $48-65m for Marsden Point, $90-141m for South Taranaki Bight, $121-178m for Port Taranaki and $138-220m for Maui-A.

Spreading these estimates across the Maximum Deliverable Quantity (MDQ) for each project enables an approximate comparison to alternative storage options, such as the Ahuroa UGS facility. While Ahuroa could potentially deliver up to 18 PJ pa of stored gas at a feed-in rate of up to 65 TJ/day, a Port Taranaki import facility could provide up to 165 PJ pa at a feed-in rate of up 500 TJ/day. Assuming a 2030 project end date infers a CRF of potentially $281-436 per GJ of MDQ (GJ.MDQ) for Port Taranaki, $477-740/GJ.MDQ for Marsden Point, $438-772/GJ.MDQ for Maui-A and $1,011-1,852/GJ.MDQ for South Taranaki Bight. By comparison, we estimate Ahuroa’s CRF lies in a range of $400-450/GJ.MDQ.

Extending to a 2050 end date reduces inferred CRFs to $277-374/GJ.MDQ for Marsden Point, $275-440/GJ.MDQ for Maui-A, $242-356/GJ.MDQ for Port Taranaki and $591-942/GJ.MDQ for South Taranaki Bight. Note these figures are sensitive to the gas send-out capacities of each project such that if the gas send-out capabilities reduced their CRFs would increase.

The significant variable costs of sending out gas from Marsden Point should also be noted when comparing options as its best case of $3.0/GJ approaches the worst case estimates for other options where best case estimates sit at $1.6-1.7/GJ.

Variable costs

The variable cost of handling and processing gas through the LNG import facilities and delivering it to the gas market would need to be added to the cost of the LNG. This fee includes the cost of regas fuel, compression, pipeline tariffs, and (in the case of the Marsden Point option) trucking delivery. We estimate these costs to be as low as $1.63-$3.41/GJ for the Port Taranaki option and as high as $3.00-$4.67/GJ for the Marsden Point option. The variable costs of the Maui-A and South Taranaki Bight options are estimated at $1.72-$3.68/GJ and $1.63-3.40/GJ respectively. Some of these costs could reduce depending on the level of gas send-out and technology used. For example, lower quantities of gas send-out would allow for passive delivery of boil-off gas at relatively low cost. Savings on high rates of gas send-out can be made by using seawater to warm LNG rather than burning gas to generate heat, although this would require consents.

Commodity costs

Given import requirements in NZ would be highly variable, depending on the power generation sector's need for marginal gas to replace hydropower in particular, commodity costs would largely reflect the Asian spot LNG price. Currently at ~NZ$14/GJ, prices have recently back down to normal levels from historic highs as a result of Russia's actions in Ukraine, the response of western governments to it, and disruptions from Covid. We note, however, that prices are likely to remain volatile for some time to come, particularly during the northern hemisphere winter and in the summer following any particularly cold winter. This is because for as long as Russian gas flows to Europe are restricted, Europe will have to rely on LNG to provide make-up supply and to fill its gas storage. A cold winter and strong Chinese LNG demand will increase prices for an extended period, even during the northern hemisphere summer, as Europe will likely have drained its currently full gas storage to meet demand and be required to refill gas storage again in time for the next winter.

3.7 NZ market accommodation

As imported LNG would serve to set a marginal unit price for gas supply when the market is short, the value of the FSRU and associated LNG would likely be spread across the wider gas market through gas trading and sale negotiations. For example, sellers of domestic gas on the spot market (which currently accounts for less than 5% of traded volumes) would seek to discover the highest price they could competitively sell gas for before it became profitable for FSRU capacity holders to send-out gas and sell it onto the spot market themselves.

Similarly, those negotiating GSAs for the supply of indigenous gas would see LNG as the alternative option against which prices and terms could be benchmarked. The option to import LNG would provide the market with a price proxy that is linked to the international price of LNG plus variable import costs. Therefore, the cost of having an LNG import option would likely become factored into wider domestic gas prices and gas purchasing behaviour beyond just the capacity holders and beyond just the volume of imported gas. Indeed, LNG import capacity holders could look to spread the cost and value of their options by more explicit means. For example, capacity holders with downstream gas distribution businesses could look to spread the option cost to their customers by passing it through as a type of insurance premium to reflect the value the FSRU brings to security of supply.

The cost of the gas could also be recovered by charging customers a price for gas that reflects the weighted average of all gas held in a supplier's portfolio. Industrial gas consumers with capacity rights would likely manage the cost as part of their normal procurement operations and sales product pricing.

Flexibility and optionality

Even if the gas market were to solely attach the cost of the FSRU only to imported molecules, an important aspect of the infrastructure is the operational flexibility that it could provide to users given its ability to instantaneously flex with demand. Indigenous gas tends to attract a price premium for flexibility which, on the basis of cost indications available in the market (Ahuroa arrangements and time swap trading as examples), appears to be in the region of $2-$5 per GJ. While this appears lower than the inferred cost of FSRU options, comparison must also consider working capital that is tied up in indigenous storage options. By contrast, working capital demands on FSRU capacity holders would likely be lower as inventory gas would only be funded when a cargo is needed.

Access to LNG imports is likely to encourage thermal generators to rethink their procurement strategies for domestic gas. For example, given the uncertainty over what their levels of future gas demand might be and that LNG imports could provide a more flexible supply solution, generators may become less willing to commit to long-term take or pay agreements for the supply of indigenous gas.

Generators could look to lease or sell 'firm and flat' gas entitlements they hold to other users such as Methanex or large industrials which could allow them to increase the utilisation and efficiency of their plant(s). In return, thermal generators could recover some of the cost of the imported gas and, perhaps, seek an option for Methanex to turn down its gas demand during periods of maximum thermal generation demand. Such a solution, combined with gas in storage in Ahuroa UGS, could potentially make up for the lower physical send-out rates available for an import project at Marsden Point.

3.8 Domestic market LNG

The establishment of LNG import infrastructure in NZ could support the uptake of small-scale LNG as a new fuel option for high-horsepower demand applications, most of which currently rely on variants of diesel or fuel oil. Boil-off gas management would mean that users would need to have high underlying utilisation, however there are numerous settings where this is the case. Marine fuels (for long distance container and cruise line shipping), heavy goods vehicles (eg the trucking module of the Marsden Point import option) and off-grid industries are each possibilities.

Marine fuels

It is likely that NZ will in time need to offer LNG bunkering to meet the strong expected growth in LNG-powered shipping, particularly in the cruise ship industry. It is also likely that long-distance freight shipping will in time also develop demand for in-country LNG refuelling infrastructure. Currently LNG bunker operations are confined to a handful of centres where shipping traffic and fuel supply converge. These include Singapore, Gibraltar, and the Antwerp-Rotterdam-Amsterdam area. Notable is that Australian FSRU projects are currently planning to offer bunkering operations, as may some of its LNG loading ports.

Within NZ, the strongest case for a local demand centre for LNG as a shipping fuel are the inter-island ferries. Both ferry operators have however recently committed to upgrading their shipping fleets to use conventional diesel.

Road transport

As a road transport fuel, LNG would be best suited to settings that involve large fleets with high vehicle utilisation. Two specific potential cases are:

1. **Long-distance road freight**: The domestic long-haul freight industry relies largely on point-to-point operations generally within a relatively small network of major centres in each island. The Ministry of Transport estimates the sector is currently served by over 150,000 heavy duty trucks. The majority are run by small-to-medium sized operators however there are several large companies with substantial fleets which are actively progressing options to reduce the intensity of their existing diesel-based operations. Options being considered include hydrogen and direct electric. LNG could also be considered.
2. **Dairy tanker fleets**: The dairy industry relies on a hub-and-spoke system where fleets are based at dairy factories and return collected milk to base for processing. Many North Island plants are already serviced directly with gas for heat and power generation which could support interest in pipeline-independent gas being available onsite in the form of LNG storage. As well as acting as a fuel depot it could

Box 9: Buquebus 'Francisco' ferry

The 99 metre long and 27 metre wide ‘Francisco’ ferry serves the River Plate route connecting Montevideo, Uruguay, with Buenos Aires, Argentina. It is one of the world’s fastest Roll-On-Roll-Off (Ro-Ro) ferries and was the world's first dual fuelled high-speed Ro-Ro ferry to operate with LNG as its primary fuel. It is capable of cruising at 52 knots and can accommodate 1,000 passengers and 150 cars on four tiers.

Built in Tasmania and commissioned in 2013, the Francisco is an aluminium catamaran that uses two Wartsila waterjets powered by two 22 MW GE gas turbines which run on both LNG (as primary fuel) and marine diesel (as backup). LNG is supplied by a small-scale onsite liquefaction plant at its home port dedicated to the service and built by Galileo, a specialist in small scale liquefaction technologies, at a reported cost equivalent to NZ$5.5m. The liquefaction plant consists of seven ‘cryoboxes’ that can produce 189 m^3 (4.7 TJ) of LNG per day. The Francisco itself has two 40 m^3 (2.0 TJ) LNG storage tanks.

In 2019 Buquebus ordered a new LNG ferry which when complete will be the world’s largest aluminium ferry at 130m long and able to carry 2,100 passengers.

Buquebus ‘Francisco’

Buquebus LNG facility

cover for pipeline and/or production outages. In addition, it is possible for LNG to be produced from bio-methane which can be sourced from on-farm waste, which in time could allow dairy operators to reduce their emissions and fuel their own fleet in a closed loop that involves on-site liquefaction.

The in-concept attraction of LNG for road freight would need to account for potential concerns over logistical and optimisation issues such as local regulatory requirements, payload impacts and resale aftermarket liquidity.

Off-grid industries

LNG distribution by road tanker and small, modular storage facilities can enable gas to be used for off-site industries. In European markets LNG has been adopted into the aquaculture, mining, forestry, and agriculture industries and could find equivalent applications in NZ. While more expensive than pipeline gas, a major benefit of having on-site LNG storage facilities is the protection it provides against possible pipeline outages.

Box 10: LNG for trucking

During 2020, UK supermarket chain ASDA received its first order of 250 Volvo-manufactured LNG powered vehicles as part of its commitment to reducing emissions. The trucks will run on bio-methane and reduce the truck fleet's CO_2 emissions by 80%. Excellent range and quieter running were two additional benefits cited by ASDA's Fleet Manager and drivers.

CNG Fuels, the supplier of the bio-methane, sources the gas from food waste and manure.

ASDA LNG trucks

Based on case studies from the UK, a skid mounted 50 m^3 (1.2 TJe) storage tank, regas facilities, and pipeline connection that can deliver 50 TJ pa of regasified LNG to existing boilers would cost around $500k with a yearly maintenance cost of around $60k. To minimise the onsite management of boil-off gas and LNG top-up, suitable off-grid customers would ideally have a high rate of plant uptime and utilisation.

Box 11: LNG for off-grid dairy applications

Dairy Partners is a British cheese manufacturer based in Wales that operates two factories at sites at Stonehouse and Newcastle Emlyn. In 2018 it converted the boiler at its Newcastle Emlyn site, which processes 150m litres of milk annually, from light fuel oil to run on LNG. The site is not on the gas network, with LNG serving as a virtual pipeline to deliver gas to the site in the same way that fuel oil was previously delivered to the site. The installation involved a single 60m^3 (1.5 TJ) above-ground storage tank which is vacuum-insulated and supported by a twin ambient vaporiser system and fitted with automatic top-up technology so that delivery is automatically scheduled once fuel runs low. LNG is delivered by truck.

According to Calor LNG, which undertook the conversion, the installation has enabled Dairy Partners to reduce both its energy costs and its CO_2 emissions by around 30% pa which was expected to provide it with economic payback within two years.

Newcastle Emlyn LNG storage tank

4. INDIGENOUS GAS STORAGE EXPANSION OPTIONS

PURPOSE

The purpose of this section is to identify and analyse feasible options to increase the system's capacity to store and cycle indigenous gas.

4.1 Storage expansion concepts

Existing gas storage capacity that is already installed and available to users has both above-ground and below-ground components, as summarised in Table 13.

There are a number of potential options to expand system storage that do not involve gas import. These are also presented in Table 13. Important to note from the expansion options identified is that they represent concepts that are technically viable. Within this option set analysis is required to evaluate the market and commercial advantages and disadvantages of each option, including the materiality that each option could provide relative to the costs of the enabling infrastructure that would be required. We analyse for these aspects in this section.

Table 13: Indigenous gas storage formats and expansion concepts/options

Storage type	Already available?	Description	Potential expansion concepts/options
1. Below-ground			
UGS		Ahuroa is NZ's only UGS facility and currently provides up to 12 PJ working gas capacity. Infrastructure and pad gas is owned and operated by First Gas but working gas is owned by entitlement holders Contact and Nova.	Conversion of the depleted Tariki gas field to a new UGS facility.
Indigenous standby gas capacity		Field-specific unutilised deliverability contracted for the specific purpose of providing standby gas. No existing examples known on a commercial basis.	Potential over-build of gas field production and/or handling capacity in excess of supply commitments for the specific purpose of providing standby capacity.
2. Above-ground			
LNG		LNG produced from indigenous gas and held as stored energy for release into the market to meet demand peaks. None currently.	To integrate with existing gas market would require construction of liquefaction, regasification and storage infrastructure.
Methanol		Methanol produced from indigenous gas and held as stored energy for release to meet demand peaks where it can be accepted into fuel applications.	Potential utilisation of existing methanol storage facilities at Methanex sites or build onsite facilities. Particularly relevant to Contact's Stratford and Whirinaki peaking plants.
CNG		Pressurised natural gas derived from either indigenous or imported gas. Very small existing domestic market.	Would require construction of large-format CNG infrastructure to integrate with existing gas market.
LPG		Some suppliers already blend LPG into the gas stream when commercially attractive to 'bulk-up' gas while maintaining it as pipeline specification.	Existing LPG handling and storage facilities could support increased volume handling to meet powergen demand.
Demand side response		Major users such as Methanex reducing demand to accommodate system peaks. Winter 2021 GSAs with Genesis Energy as example.	Opportunistic, relies on willing buyer and willing seller at any given point in time.
Line pack		Maui pipeline line pack is maintained at around 300 TJ within a relatively tight tolerance of +/- 30-40 TJ.	Scope to increase beyond current levels appears marginal given pressurisation constraints.

Source: Enerlytica

While perhaps obvious, nonetheless worth acknowledging when considering potential indigenous storage expansion options is that adding capacity to store indigenous fuel does not by itself increase the size of the fuel pool. If gas is not available to procure from the market to enable inventories to be built to support cycling through handling infrastructure the addition of storage serves little practical purpose. This reality has been observable in NZ in recent years through constraints Contact Energy has faced that have prevented it from using the full extent of its Ahuroa UGS storage and cycling entitlements due to low gas availability.

This aspect is a key point of difference to import options, including import LNG, which as well as providing storage capacity would also serve to increase the size of the fuel pool in NZ.

1. Below-ground storage options

UGS

UGS involves developing underground geological features for the explicit purpose of storing and cycling gas. UGS formats typically feature one of four formation options: depleted oil and gas fields, aquifers, abandoned hard rock mines or salt caverns. All are common internationally, particularly in North America (the US alone has nearly 400 dedicated UGS facilities), Europe and Russia. The geological characteristics of each project vary however host formations typically comprise storage and/or reservoir rock that has both high permeability and high porosity with an impermeable cap or seal.

UGS developments have both below-ground and above-ground work programme components.

- **Below-ground**: When using depleted oil and gas fields, the drilling of additional wells to enable the cycling (injection and extraction) of stored gas is usually required. Often when developing projects around depleted fields there are existing wells that can be used for cycling operations. Not all depleted oil and gas fields are suitable for UGS – for example a field with low porosity reservoir rock or that is prone to water flooding is unlikely to be suitable for UGS as these characteristics can reduce the efficiency and increase the uncertainty of gas injection, storage and withdrawal operations. An often-overlooked component of below-ground UGS development spend is “pad” or “cushion” gas which is gas that is permanently held to provide pressure support to enable the cycling of working gas. Pad gas can require a large commitment of ‘soft’ capital beyond the ‘hard’ cost of drilling wells and installing supporting infrastructure.
- **Above-ground**: Surface work typically involves the installation of compression equipment to support cycling operations and pipework to connect the facility to the gas network and/or downstream assets.

AGS

AGS is NZ’s only standalone UGS facility and therefore a valid NZ analogue against which potential further UGS expansions can be benchmarked from. The section that follows provides an account of the development of AGS and an indicative analysis for what the development of additional UGS capacity could involve.

AGS makes use of the depleted Ahuroa gas-condensate field which was originally discovered as part of a Petrocorp-led exploration campaign in 1986-87 that targeted an area around 7km East of Stratford. That campaign resulted in the discovery of the Tariki, Ahuroa, Waihapa and Ngaere fields, which together are widely referred to in the industry as the “TAWN fields”.

The Ahuroa-2A well drilled in 1986 revealed a gas-condensate discovery within the Oligocene-aged Tariki Sandstone at a depth of around 2.5km with a gross interval thickness of around 200m. It was not until 1995 that Ahuroa was developed and well site facilities built. Production was relayed via pipeline to the Waihapa production station which received and processed all TAWN field production. Over its 13-year producing life from 1996 to 2008 Ahuroa yielded 50 PJ of gas and 1.1 mmbbl of condensate.

Ownership history

The TAWN assets have been the subject of a series of ownership changes since their discovery and subsequent development (Table 14).

Petrocorp sale to Fletcher Challenge Energy

Petrocorp (a former state-owned enterprise) was acquired by Fletcher Challenge Energy (FCE) in 1988 as part of a government privatisation programme. Ahuroa was only one asset of an extensive portfolio of production and exploration interests held by Petrocorp at the time.

FCE sale to Swift Energy

The acquisition by Shell of FCE in 2000 saw the Commerce Commission impose sale conditions that required Shell to divest a number of FCE assets including the TAWN fields. In November 2001, Shell announced the sale of the TAWN assets to US company Swift Energy for what was reported at the time to be a sale price of $130m.

Swift Energy sale to Origin Energy and Contact Energy

In 2007 Contact Energy and its then parent company Origin Energy announced their joint acquisition of the TAWN assets for US$87.8m (~NZ$115m). Of this, Origin and Contact agreed that Contact would pay NZ$54m for “*the right to own and develop the Ahuroa gas field as an underground gas storage facility and purchase the remaining gas and LPG reserves in the Ahuroa reservoir.”* The payment did not include future capital costs to develop Ahuroa into a UGS facility.

Table 14: TAWN ownership history

Period	Owner / acquiror	Details
1986-88	Petrocorp	Original discoverer of TAWN fields
1988-2000	Fletcher Challenge Energy	Acquired with FCE acquisition of Petrocorp in 1988
2000-01	Shell	Acquired with Shell acquisition of FCE in 2000
Nov 2001	Swift Energy	Divested by Shell to comply with Commerce Commission conditions imposed with its acquisition of FCE. Swift is reported as having paid $130m for the assets
Dec 2007	Origin Energy + Contact Energy	Acquired TAWN assets from Swift Energy for US$87.8m of which Contact paid $54m for rights to develop Ahuroa as a UGS facility
Oct 2013	NZ Energy Corp / L&M Energy	Acquired TWN assets from Origin for CAD$33.5m
Dec 2017	First Gas	Acquired Ahuroa UGS from Contact for $200m

Source: public information, Enerlytica

Contact's investment case centred on Ahuroa's sandstone reservoir which is sealed in impervious clay. With porosity and permeability of 18.8% and 313mD respectively, Contact and Origin assessed Ahuroa as presenting an ideal geological and commercial setting for a UGS development.

Contact and Origin said they had worked together to form the TAWN offer. Contact undertook due diligence prior to the acquisition and, through an independent report commissioned by the Independent Directors Committee, determined the amount Contact would be willing to pay for the option to develop gas storage. Despite the conflict of interest between Origin and Contact, the independent report was not made available to shareholders at the time of the transaction.

Contact's decision to invest in and develop Ahuroa was part of its response to perceived gas availability constraints and a sharp increase in wholesale gas prices during the early 2000s. AGS was initially scoped to enable Contact to store surplus gas it would previously have had to surrender, use, or sell at a loss under take-or-pay GSAs. The development of AGS sat within a strategy of seeking to reduce its gas use and improve the integration of its upstream and downstream fuel assets and interests by moving further up the fuel supply chain.

The acquisition was completed in June 2008. Contact paid a further NZ$24m for 4PJ of pad gas which equated at the time to a per-unit equivalent of ~$5.90/GJ. Working gas capacity at the time was stated as 10-15 PJ.

Development involved the drilling of new wells and installation of compression equipment to support gas injection and withdrawal cycling operations. Contact and Origin agreed that drilling, design, development and operations were to be managed by Origin.

When it announced the acquisition, Contact said it expected the facility to be operating by 2010 and require a further investment of $150m to complete, excluding the cost of additional gas to be purchased and injected. The inference therefore was that the total cost to Contact would be around $200m and that commissioning would occur by around the end of 2009. The development phase ran over both time and cost estimates and by mid-2009 Contact was referring to AGS as a "$250m" project. Final commissioning did not occur until February 2011 (Table 15).

Figure 29: Ahuroa-B wellsite and facilities

Source: Taranaki District Council

Table 15: AGS development timeline

Date	Milestones
Dec 2007	Origin-Contact deal to acquire TAWN assets announced
Jun 2008	Deal completes
4Q 2008	Injection of pad gas commences using existing compressor
2008-09	Ahuroa-2A redrilled to enhance flow, 3 new sidetracks drilled (stage 1)
4Q 2009	New compressor installed & commissioned
1Q 2010	Drilling of three new wells completed: Ahuroa-3, Ahuroa-4 and Ahuroa-5A. Each ~2,300m deep.
3Q 2010	Compressor reconfiguration completed
4Q 2010	Pad gas filled to 5.7PJ, working gas to 8.3PJ
Dec 2010	NZP&M grants Contact a 40-year mining permit PMP 52278 to operate Ahuroa
1Q 2011	Ahuroa Stage 2 operational
May 2011	Ahuroa and Stratford OCGTs each formally commissioned

Source: company announcements, Enerlytica

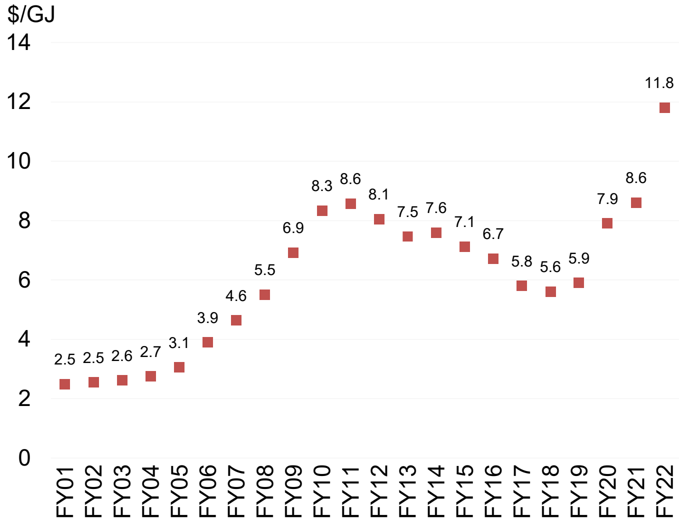
Contact's central consideration when it scoped the development of Ahuroa was to support its planned build of new gas peaking plant at a site adjacent to its existing 377 MW Taranaki CCGT (known as TCC) located just outside Stratford. The Ahuroa wellsite (Figure 29) is located 9km northeast of TCC. Contact did subsequently build two standalone 100 MW high-efficiency OCGTs adjacent to TCC, with the site now known as the Stratford Power Station (SPS). The OCGTs were commissioned in mid-2011, shortly after AGS itself entered operation. AGS's withdrawal capacity was rated to 45 TJ/day while injection capacity was 27 TJ/day.

Following commissioning, Contact began injecting excess gas into Ahuroa at strong rates, increasing its working gas balance to 12 PJ by the end of the 2011. Injected gas represented gas excess to requirements from Contact's portfolio of Pohokura and Maui entitlements and was expensive. For its 2011 financial year Contact's average cost of portfolio gas was reported as $8.57/GJ (Figure 30).

The high carrying value of its inventory gas during a period of significant overbuild of new generation capacity and when alternative energy storage options were materially cheaper resulted in an extended period of relatively low wholesale gas and electricity prices which prevented Contact from being able to cycle gas freely from AGS to meet electricity market conditions. While withdrawing gas for feed-in to its SPS units incurred a very low cash cost, the amortisation cost of using stored gas was calculable against average carrying value.

Eventually, with its 2016 financial year results Contact wrote-down the carrying value of its 15.7 PJ of AGS working gas held at that time from ~$8.00/GJ to ~$5.75/GJ. The move effectively served to capitalise the amortisation impost of using working gas given the oversupply in gas and electricity markets at the time.

Figure 30: Contact Energy average cost of gas

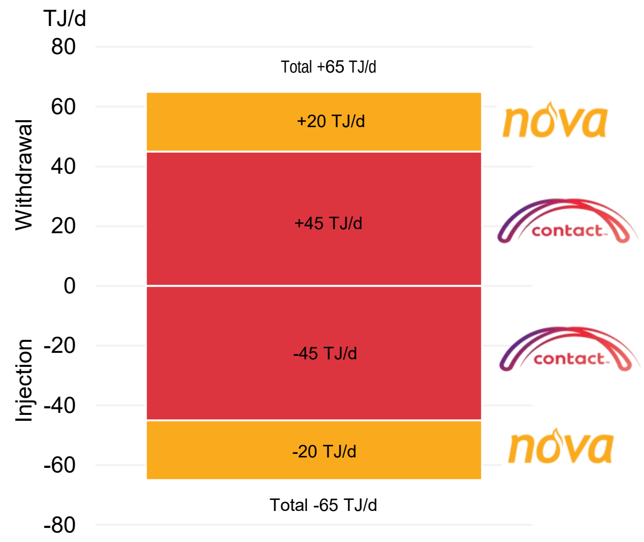


Source: company data, Enerlytica

Origin sale of TWN interests to NZ Energy Corp

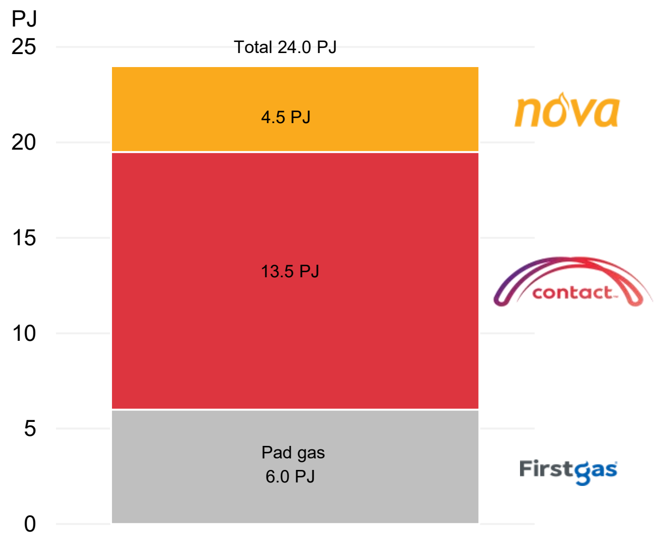
In May 2012, Origin announced the sale of its TWN asset portfolio including its operatorship of AGS to New Zealand Energy Corp (NZEC). The sale took 17 months to complete while NZEC secured financing arrangements during which time Contact completed a new 8.7km pipeline connecting the Ahuroa site directly with its SPS site, thereby creating a gas loop with the Waihapa production station and providing Contact with the flexibility to bypass Waihapa to connect directly with the high-pressure gas transmission network if it wished to do so. The 450mm diameter pipeline operates at 45 bar, can carry 170 TJ/day and hold line pack of 4 TJ and was therefore considerably over-sized against Ahuroa's original handling capacity. The redundancy was

Figure 31: AGS gas cycling entitlements



Source: Enerlytica

Figure 32: AGS pre-2023 gas storage entitlements



Source: Enerlytica

installed in part in anticipation of potential future expansion of AGS. Partly due to the flexibility that the new pipeline provided, since Origin's exit Contact managed to halve AGS's operating costs to around $6m pa.

First Gas acquisition

In December 2017, Contact announced the sale of AGS to First Gas affiliate company Gas Services New Zealand Ltd (GSNZ) for $200m. The structure of the deal saw GSNZ, via the Flexgas brand which it now markets AGS services through, acquire all Ahuroa infrastructure including PMP 52278, the 10.5 km^2 petroleum mining permit within which the facility's above-ground and below-ground infrastructure is located. Contact retained title to all inventory gas excluding 6 PJ of pad gas.

While GSNZ is an interconnected party to the transmission system, it is not a gas producer, wholesaler, shipper, or retailer.

The deal included an initial 15-year storage access agreement under which Contact would pay First Gas a $20m (real terms 2018) fixed fee to secure 75% of existing injection and withdrawal capacity (ie 20.25 TJ/day injection, 33.75 TJ/day withdrawal). Once the initial term expires in 2033 Contact holds options to exercise five-year extensions to bridge through to 2050.

Contact had itself been considering expansion options and had already secured all necessary consents and approvals to do so. During Contact's ownership of AGS no third-party gas was known to have been handled. A central component of First Gas's investment case however was to extend access to AGS to other parties. Contact also had an incentive to see third parties contract capacity as the fixed annual fee it pays would decrease if third party users contracted for access.

Reflecting this, the sale agreement included an obligation on First Gas to expand AGS within two years of deal completion to 65 TJ/day for both injection and withdrawal. The expansion project that followed, which was completed in 2H 2020, saw three new gas compressors and a gas dehydration unit installed. Following its completion Contact's cycling rights increased to 45 TJ/day in both directions leaving First Gas with 20 TJ/day to market to a third party.

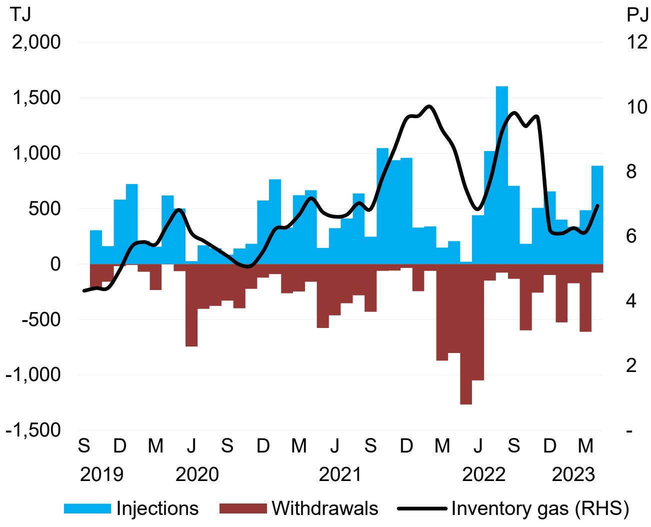
A further important aspect of the sale was agreement between the parties that the 20 TJ/day expansion and its associated storage volume would be the first to be commercially met from the facility. This meant that should gross storage and/or cycling capacities be downgraded at some future time then entitlements held by parties other than Contact would be the first to be supplied from the lower storage and cycling entitlements.

In July 2019, First Gas announced a new 15-year access agreement with Nova Energy under which Nova acquired rights to the 20 TJ/day of expanded cycling capacity and 4.5 PJ of storage. On announcing the deal Nova emphasised the fit with its new 100 MW OCGT at Junction Rd that was under construction at a site on the outskirts of New Plymouth, which was commissioned in early 2020.

Post-expansion steady state operation 2020-21

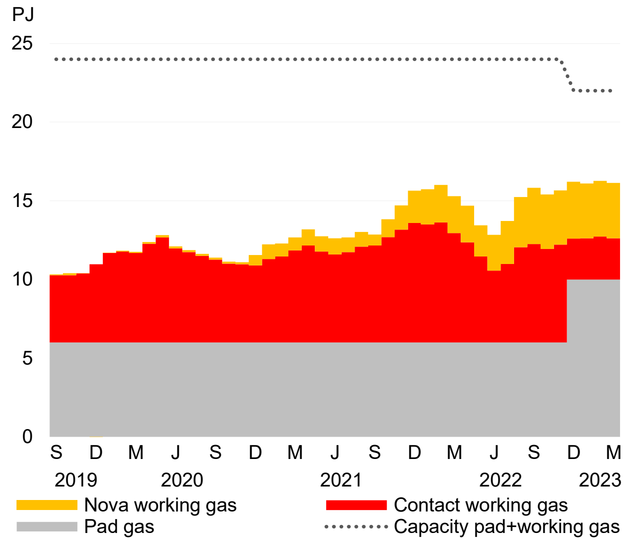
Ahuroa has operated on a long-term pad gas base of 6 PJ and gross working gas capacity of 18 PJ. At the time it was signed, the Nova agreement effectively saw that it and Contact had acquired all storage and cycling (Figure 31) and capacity (Figure 32) rights. For Contact and Nova, AGS serves essentially as a working capital facility that enables them to deposit gas produced or acquired on favourable terms and withdraw it to use when energy market conditions assign a higher value to it.

Figure 33: AGS working gas flows & balances



Source: GIC data, Enerlytica

Figure 34: AGS pad+working gas historic holdings



Source: GIC data, company data, Enerlytica

Cycling gas enables several strategic and tactical options to help holders with managing fuel portfolios, including:

- Supporting Contact and Nova's thermal generation activities by enabling them to meet wholesale electricity price needles with gas over which it has price and dispatch control
- Take short-term opportunities to buy and sell spot gas
- Offer gas market balancing
- Offer gas storage services to third parties

Low gas market liquidity between 2018 and 2022 limited the ability of Contact and Nova to use AGS's cycling and storage capacities to their respective full extents. Over this time total working gas did not exceed 10.0 PJ (Figure 33) within which Contact's working gas balance did not exceed 7.6 PJ of its available 13.5 PJ and Nova's did not exceed 3.6 PJ of its 4.5 PJ entitlement.

Performance decline 2021-

In February 2022, Contact announced that it had been advised by First Gas of an unexpected and unexplained increase in pressure within the Ahuroa reservoir. A joint technical working group of Contact and First Gas (but notably not Nova) representatives was formed to investigate the anomaly and advise on a course of action.

In December 2022, Contact announced the results of the investigation which concluded the increase in pressure as due to water ingress causing the displacement of stored gas from the reservoir. The working group concluded at that time that total gross working gas storage capacity (excluding 6 PJ of pad gas) sat in a likely range of 10-12 PJ, making for a downgrade of between -33% and -44% on the 18 PJ of gross working gas storage capacity contracted by Contact and Nova.

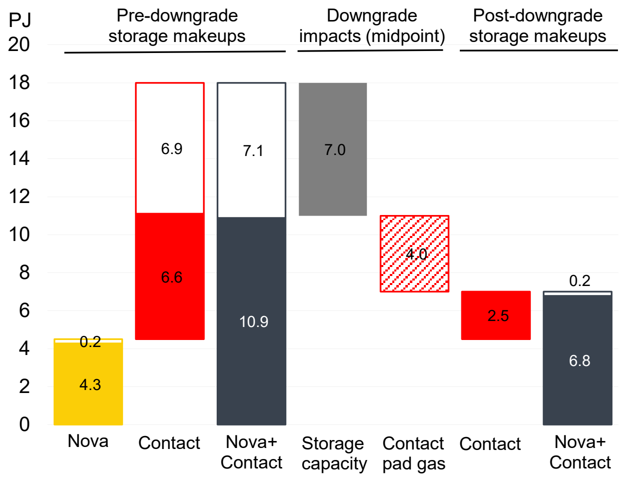
Atop the headline downgrade to storage, to be able to maintain the 65 TJ/day of gross contracted cycling capacity the working group advised that 4 PJ of working gas would need to convert to pad gas. In other words, for AGS to retain its existing ability to inject and extract gas at contracted rates, the advice was that working gas storage would need to reduce to between 6 and 8 PJ.

The nature of the commercial arrangements between the three parties see that Nova's storage and cycling entitlements are the first to be met, meaning that Nova's full 3.5 PJ storage entitlement remains intact, leaving a residual of between 2.5 PJ and 3.5 PJ to Contact's account. As at the close of December 2022, we calculate Contact and Nova as having held 6.5 PJ and 3.5 PJ of working gas entitlements in AGS respectively. In other words, at that point Contact had effectively already used its full storage capacity under its downgraded entitlement while Nova had just 0.2 PJ of its unchanged entitlement remaining (Figure 34 and Figure 35).

With the release of its half-year result in February 2022 Contact announced a $120m pre-tax charge as a writedown to reflect its assessment of the reduced benefit it expects to realise from what remains of its AGS access agreement against the costs it expects to incur by meeting the fee payment schedule on the contract out to its 2034 end date. Contact says the situation will be reviewed on an ongoing basis with the possibility of revisions should reservoir performance change against that assumed for the writedown scenario.

Contact's expert has said AGS's storage capacity could be improved if the facility is operated at higher pressure and at a higher cycling rate, however any increase would likely be capped at +3 PJ and take several years to achieve.

Figure 35: AGS storage entitlements vs utilisations, estimates at 31 December 2022



Note: solid blocks show stored gas, transparent blocks represent available (unused) storage

Source: GIC data, company data, Enerlytica

Since confirming the downgrade the parties have agreed to operate AGS in this mode. While still in the very early stages, Contact has said there are positive signs that operating in this mode is improving the storage performance of the reservoir.

The experience at AGS does however highlight the issue of how commercial risk is managed between contracting parties of storage capacity when that capacity involves underground storage which by definition carries with it at least some component of sub-surface risk.

UGS expansion options

UGS expansion options can be thought of as falling into one of two types:

1. **Standalone UGS** – capacity developed explicitly for the purpose of providing UGS either via an expansion of an existing AGS facility or the construction of a new UGS facility.
2. **Integrated UGS** – development of UGS capacity that is integrated with existing field operations.

1. Standalone UGS

AGS expansion

Under its current 65 TJ/day cycling rating AGS is understood to be optimised to its existing infrastructure. In other words, above-ground compression is broadly matched to optimise below-ground deliverability from existing wells. There remains scope however to further expand cycling capacity by adding additional compression and wells. Compared to the 2018-19 expansion programme however which added only compression to AGS's handling capacities, further expansion would be relatively capital intensive as it would require both additional compression and the drilling of new production wells. Expansion could in theory increase cycling capacity to up to 150 TJ/day without impacting storage capacity.

Despite the apparent potential to increase AGS's cycling capacity, the uncertainty towards the extent of its physical storage capacity and the negative implications for Contact's commercial position make the feasibility of an expansion scenario in our view unlikely for the foreseeable future. More likely is a remediation-focussed work programme focussed on restoring AGS's existing working storage capacity. As a result, we do not provide for a AGS expansion in our scenario modelling.

Tariki UGS development

Entirely separate to a brownfield expansion option at AGS is the potential development of a new and standalone UGS facility using the depleted Tariki field. Under current work programme conditions associated with its operatorship of PEP 38138 (Tariki), NZEC is required to work to "*transform the Tariki field into a gas storage or carbon sequestration facility*".

A notable aspect of Tariki is that the field is reported to sit in an isolated fault block which does not recharge with water and which has high reservoir pressure. Both characteristics are ideal features for a UGS development.

NZEC's advancing of a potential Tariki UGS project is clearly scoped to meet past interest expressed by Genesis for storage capacity of up to 20 PJ and cycling of up to 55 TJ/day. NZEC has indicated that Tariki could deliver 75 TJ/day of cycling capacity, inferring therefore that 20 TJ/day of uncommitted cycling capacity could be made available to other market participants.

Key technical and commercial assumptions in our modelling of a Tariki UGS development include:

- **Drilling:** Three wells required to provide injection/extraction capacity of up to 75 TJ/day. One existing well could be used towards meeting this, meaning two new wells would need to be drilled at an assumed cost of $8m apiece. We have assumed a further $8m as contingency and to cover the costs of re-entering the existing well.
- **Compression**: Gas would be received from the Waihapa production station at a pressure of 90 bar. New onsite compressors would be required at Tariki to enable cycling capacity at an assumed cost of $17m.
- **Extraction**: Existing withdrawal compression of 45 TJ/day is already onsite and available. To deliver 75 TJ/day would require a duplicate low-temperature separation unit. Estimated cost $15m including $5m to refurbish existing plant.

Figure 36: Potential Tariki UGS development pathway

Date	Milestones
2021	3D seismic acquisition programme
2022	Seismic processing & interpretation, commercial counterparty discussions
2023	Detailed FEED, finalise commercial terms with counterparties, FID
2023 - 2H 2024	Drilling, construction of above-ground compression & handling equipment
2H 2024	Commissioning

Source: Enerlytica

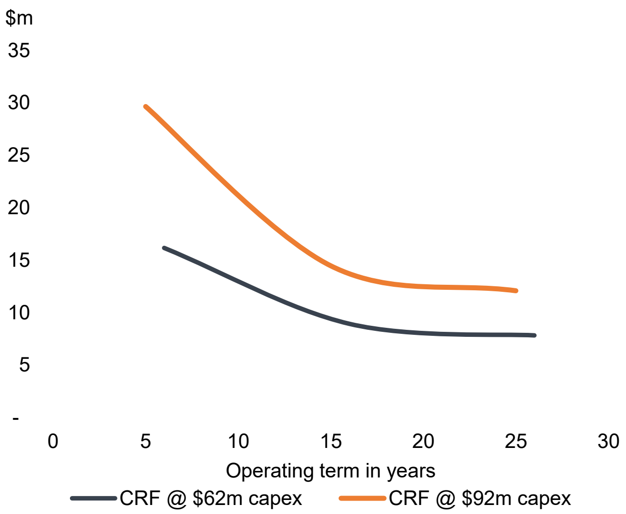
- **Pad gas:** Cushion gas is required to support working gas. Volumes remaining in the field are understood to be sufficient to provide adequate pressurisation, therefore requiring no additional pad gas to be injected.

A potential development work programme and timeline to bring a Tariki UGS project to market is shown in Figure 36. We model a development cost including pad gas, which already resides in the field, in a range of $62-$92m with the upper bound incorporating a 50% contingency loading atop our base case.

The development timeline in Figure 36 infers a six-year operating horizon ahead of 2030. Applying to this window capex of $62m and a 10% required ROI infers a CRF of $215/GJ.MDQ. Extending the ROI window to 2050 would reduce the CRF on the same capex and ROI assumptions to $104/GJ.MDQ.

Should a UGS development not proceed at Tariki, it appears likely that NZEC would, contingent on funding and approvals, instead proceed with a bypass gas drilling programme to produce what would have been the pad gas for the UGS project.

Figure 37: Inferred UGS CRFs on 10% target ROI



Source: Enerlytica

2. Integrated UGS

Pohokura

The Pohokura JV installed a gas reinjection cycle in 2012 during a period of excess gas market supply to enable increased condensate production by allowing for unsold associated gas to be reinjected back into the field. Pohokura therefore has existing above- and below-ground facilities that could potentially support gas storage cycling.

A major drawback of a Pohokura UGS concept however is that the field's subsurface profile is not well suited to gas storage. The field's reservoir is made up of relatively narrow stratigraphic bands that make gas injection and withdrawal inefficient compared to the multidimensional reservoirs at Ahuroa and Tariki. Furthermore, the existing reinjection well has since been reassigned to production, inferring that converting Pohokura to enable third party gas storage and cycling would likely require a number of new wells and pipelines to enable connection with the offshore reservoir. Because of their extended reach, any new wells would be costly at perhaps $30m apiece. Additional compression would also likely be required.

Pohokura's existing production operation is a further complexity given that injected gas would likely be comingled with in-situ Pohokura gas in the existing reservoir, leaving it less certain that injected gas would eventually be fully recovered. Such a feature could prove unacceptable to users that would not want production risk reattached to gas which they have already paid for.

A further complication is the field's complex ownership structure and the JV's current focus on rebuilding underlying field production, which could mean that that any suggestion of extending Pohokura operation to offer UGS capability would be a low priority for the JV.

Maui

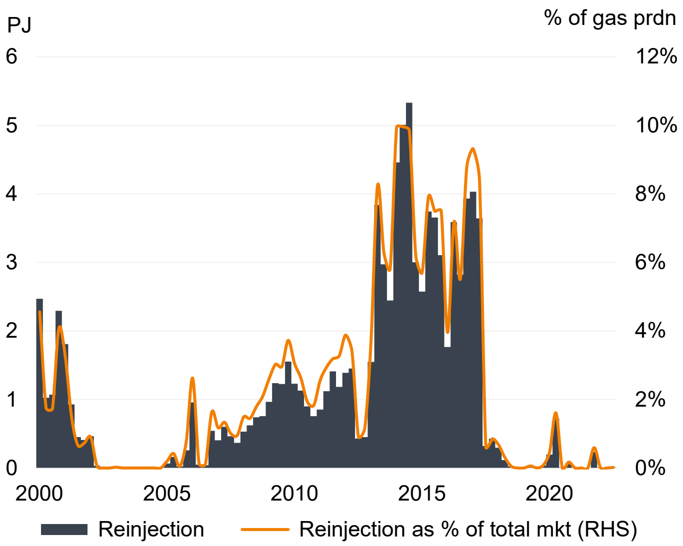
The Maui field also has UGS potential but like Pohokura faces significant technical and economic viability challenges. Central to Maui's production profile is its aquifer-driven production system under which remaining hydrocarbons are compressed from below by water that is already present in the porous reservoir rock. This is a highly desirable feature of producing fields as it sustains reservoir pressures and production flow rates. It is however not desirable for UGS as substantial additional compression is required to inject gas into the field and cycling rates may not be sustainable for the extended periods required by potential users.

In addition, being offshore, infrastructure that serves the Maui field is significantly more expensive to install and maintain. Construction timelines would also likely be much longer while long-lead time items are purchased and the logistics of offshore installation are managed. A further complexity lies in Maui's status as a mature field that requires significant ongoing reinvestment to extend its operating life. Future late-life work programmes are likely to be intensive and could see competition for technical and commercial resources from which a UGS development programme would likely be lower priority.

Indigenous standby gas capacity

This refers to latent supply-side capacity that either does or potentially could exist in producing fields and which could be called upon during times of short supply. The concept is like that of UGS in that it represents gas that is held in a producing field and available to be produced dynamically but which is not immediately required by the market. A key difference is that UGS is purpose-built to respond to injection and withdrawal decisions with very little notice whereas production throttling of fields that are in continuous production can impact field performance and risk production system deterioration. UGS is also specifically designed to store gas whereas most producing fields in NZ present gas-condensate wellstreams. This means that throttling of gas production to meet market demand also impacts the production of associated liquids (oils, condensates and/or LPGs) which can significantly impact overall field economics. It would therefore be preferable to target dry gas fields for standby gas production, of which there are few if any operating in NZ.

Figure 38: Gas system reinjection, quarterly 2000-2022



Source: MBIE data, Enerlytica

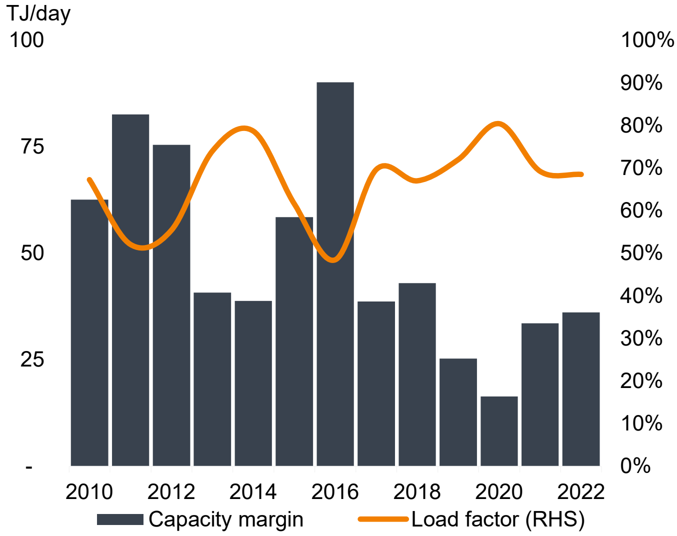
Currently available physical standby capacity

The extent to which there may be spare physical standby capacity already available in the market involves assessing whether during periods of average or near-average demand producing fields could dynamically respond by increasing production to fill for periods of supply shortfall and whether that ability to respond is sufficient to meet the full call of market demand in times of supply stress.

There are a number of indicators in the market that suggest there to be little such spare capacity able to be called upon. These include:

- The period between 2018 and 2022 has been one generally of significant market stress with reduced supply seeing wholesale gas sellers impose demand curtailments on their customers. In several cases this has seen Force Majeure called by sellers under their supply contracts with buyers. It is not in the interests of suppliers to impose cuts on their customers without having investigated and eliminated feasible opportunities to fill unmet supply with alternative supply lines. This is particularly the case given the foregone value of liquids associated with reduced gas supply.
- Gas reinjection volumes have reduced to very low levels since 2018 (Figure 38). During periods of gas market oversupply, as was the case across much of the decade prior to 2018, suppliers have used gas reinjection as a means of supporting continuous field production while providing a sink to manage gas that is produced for which no buyer exists (producers typically would much prefer to sell gas to market than reinject it back into the field). Reinjection rates increased sharply in 2013 following the commissioning of a new reinjection cycle at Pohokura however have fallen back to negligible levels since 2018, suggesting that producers have had very little scope to increase dynamic supply from existing fields.
- Market disclosures by gas producers of handling capacities of individual gas plants suggest there to be significant headroom available to increase production if gas was available. For example, in the first six months of 2021, Pohokura dispatch averaged 116 TJ/day and peaked at 133 TJ/day, each of which is well below the 206 TJ/day maximum deliverability (which we infer as a proxy for gas plant capacity) reported by operator OMV effective as at 1 January 2021.
- Production data suggests that available flexibility from key swing fields, particularly Maui (Figure 39), continues to fall with deliverability decline. The corollary is that capacity utilisation continues to increase.

Figure 39: Maui field flexibility, 2010-2022



Source: OATIS data, Enerlytica

While the direction of these trends could stabilise or even reverse in future depending on how underlying supply and demand each unfold, this will not detract from the reality that rational operators of gas-condensate fields will seek to produce as quickly as possible. This is particularly the case with offshore fields which have high operating cost bases that require operators to try and maximise production to provide as much cost coverage as possible.

Potential future standby capacity

Also feasible is the possibility of a gas producer opting to invest with the specific intention of bringing new standby capacity (but not necessarily production) to market. This would see a developer invest with the specific intention of offering capacity to the market that in 'normal' market circumstances will not be produced. The concept is similar to that of peaking generation providing reserve capacity to the electricity sector. It is not however the same as where a market may present unproduced-but-available gas that is the result of open market operations, such as was the case in NZ during the period following the commissioning of the Pohokura reinjection module in 2013. It is instead standby gas capacity that is developed with the specific intention of not being produced unless it is called on.

Internationally there are very few known cases where this model operates. In most, investment cases are underwritten by government agencies to meet security of supply objectives and involved the development of high-probability dry gas plays largely absent of liquids.

The likelihood of a E&P investor proactively progressing a work programme in NZ to bring standby gas capacity to market is in our view low as:

- Opportunity costs are very high due to the presence of associated liquids in the gas stream. Compensating for this via a capacity charge would likely be expensive.
- Success rates in NZ are comparatively low, making it less likely that the risk/reward profile of production deferral would be acceptable to a local investor given development would not involve continuous production.
- The sector is already running at high capacity with the major players advancing work programmes targeting higher-impact plays than what a standby case would yield. Maui-A, Maui-B, Pohokura, Mangahewa, Kapuni and Kupe each have major work programmes currently being advanced and/or undertaken. There is significant uncertainty as to whether the major players would have the human and commercial capacity to progress the additional and arguably less attractive work required to bring standby gas capacity to market.
- Fields that present the strongest development potential are, on the basis of reported reserve and resource estimates, the onshore deep gas-condensate Mangahewa and Kapuni fields. These fields have characteristics that require them to remain in continuous production which reduces the scope for them to be able to provide standby capacity.
- Uncertainty towards the Government's energy policy programme and its objectives for the oil and gas sector has reduced the appetite of international investors to commit capital in favour of the NZ E&P sector irrespective of the investment proposition.

2. Above-ground storage options

Domestic LNG

Domestic LNG liquefaction, storage, and regasification infrastructure, often referred to as a "LNG peak-shaver" because such facilities serve primarily to balance supply with demand peaks, would store gas across time within the market and could also serve to provide LNG for transport and off-grid requirements in much in the same way that LPG already does. LNG import would not feature under a domestic-only concept.

In many respects the role that a domestic LNG peak shaving facility could play in the market would be very similar to UGS and the service that Ahuroa currently provides. It would however also face working capital demands by needing to fund stored and "heel" LNG. The heel LNG, similar in concept to pad or cushion gas, is retained in storage when all other gas has been regasified to ensure that facilities are kept cold. However, compared to cushion gas at UGS facilities, heel LNG only comprises a relatively small volume of total storage capacity, at around 5%. The main benefit of a LNG peak shaving facility over UGS is that the facility could be more specifically sized to meet market needs and provide more flexible rates of comparable "injection" (in this case, liquefaction) and "withdrawal" (regasification).

Figure 40: LNG peak shaving facility

Source: McDermott

The main drawback is that LNG peak shaving facilities are considerably more expensive to install and can consume significant amounts of energy themselves in the liquefaction and regasification processes, with energy losses typically of between 2-5% of total gas inputs.

LNG peak-shaving facilities are most common in North America where there are around 50 such installations with the largest able to store up to 4.7 PJe of gas. With these operations, surplus gas is acquired inexpensively during off-peak (typically summer) periods then liquefied and stored until peak demand (typically winter) periods when it is regasified to meet power generation and winter heating load. The commercial model therefore relies on trading arbitrage, as is the case with UGS in NZ.

A peak-shaving solution scoped to provide 10 PJ of deep storage in NZ would be twice as large as the largest peak shaving facility currently operating anywhere in the world. The required scale would in fact be comparable to the storage capacities of large land-based LNG import terminals. Due to the infrastructure required for liquefaction and additional onshore storage requirements, such a facility would be considerably more expensive than one required for imports alone. We estimate that a 10 PJe-sized facility able to liquefy and regasify 75 TJ/d would likely cost between $5.4 to $7.8 bln. Applying a 10% ROI over a payback window to 2050 in our Best Case scenario infers a CRF of $9,742/GJ.MDQ.

Also worth noting as a disadvantage of a LNG peak shaving facility in NZ is that, if inactive for an extended period, the issue of boil-off gas and LNG "weathering" would likely become an issue. While it would take many years for 10 PJ of insulated LNG to boil away, being injected into the grid as it did so, the comparatively rich nature of gas in NZ would make any remaining in-tank LNG more susceptible to degrading to become off-spec against gas network specifications. This is because methane would boil-off ahead of heavier hydrocarbons in the gas stream, making the remaining gas richer in calorific value. This can be remedied by constantly re-liquefying the boil-off but doing so attracts higher running costs.

An important strategic benefit that would accompany a LNG peak shaving facility is that the liquefaction cycle could provide pipeline-independent gas if paired with truck loading facilities. This would allow LNG to be shipped to customers, most likely industrial sites, via containerised bullets able to store around 1 TJ apiece. The virtual pipeline this provides also has the potential to enable off-grid industrial users to switch from coal to gas and to substitute pipeline infrastructure in the event some stretches of the high-pressure distribution network are no longer economic or practical to maintain in the event that wider gas demand declines. The virtual pipeline concept has been used to service a natural gas distribution network in Northern Scotland that is not connected to the UK high-pressure network. Domestic liquefaction facilities could also support the use of LNG as a diesel alternative transport fuel in the maritime and road haulage sectors.

A virtual pipeline facility capable of transporting 20 TJ/d, which is equivalent to the demand profile of NZ's largest industrial users, would we estimate cost $254-379m to build. In a best case scenario with a payback period to 2050 we estimate a total fee to cover CRF and fixed opex of $33m pa. As such, we consider it highly unlikely that a LNG virtual pipeline system could compete with the economics of operating existing pipeline infrastructure.

Methanol storage

Methanol offers an indirect means of storing natural gas and could be looked to as a means to support domestic energy storage and security, with power generation a particular area of interest. Reforming natural gas into methanol enables hydrocarbons to be stored in bulk as a liquid at ambient temperature and storage facilities can be designed to hold whatever volume of methanol that is required. Such a facility could in concept operate in the market similarly to LNG peak shaving albeit with some major differences, some of which are highly advantageous.

Advantages

The central attraction of a methanol option is that with the Motunui and Waitara Valley plants NZ has existing access to a continuous supply of methanol. Currently most NZ-produced methanol is exported to customers in the Asia Pacific region that do not operate on domestic market price signalling. As such, methanol could be procured from Methanex at an export equivalent netback.

As a commercial proposition, Methanex is very much more likely to prefer selling methanol supply into the local market than ramping its gas consumption up and down to support other NZ gas users. This is because the ramping of capacity utilisation of their methanol production facilities comes at a cost of a sizeable reduction in operating efficiency and therefore site economics. Ramping plant

Table 16: NZ installed methanol tankage

Site	000 m^3	PJe
Motunui	170.5	2.7
Waitara Valley	19.0	0.3
Omata Tank Farm	85.5	1.3
Port Taranaki	60.0	0.9
TOTAL	**335.0**	**5.0**

Source: Enerlytica

also reduces methanol production and with that Methanex's capacity to meet its Asia Pacific customer order book, whereas after it has been produced, methanol can be stored and moved in bulk to optimise portfolios and supply chains across Methanex's global portfolio.

From a generator's perspective, buying methanol on a spot basis would likely be seen as a more efficient use of working capital than otherwise needing to procure and store an uncertain volume of gas for an uncertain period.

From Methanex's perspective, growing demand in the domestic methanol market is likely to be viewed positively, particularly where it supports increased security of electricity supply, as would opportunities to operate its NZ plant at a higher utilisation rate than might otherwise be the case. Commercial mechanisms could be structured in a number of ways including arm's length (under which generators simply buy methanol on a vendor basis) and/or tolling (under which generators supply gas to Methanex for processing into methanol). Under these mechanisms there may also be potential for existing gas entitlements held by generators to be transferred to Methanex.

A key advantage is that Methanex already operates sizeable methanol storage infrastructure in NZ, some of which appears to be underutilised. While exact numbers are not known, we estimate a total of 5 PJe of methanol storage as operating across Methanex's Motunui, Waitara Valley, Omata Tank Farm and Port Taranaki tankage. With Waitara Valley not currently operating and unlikely to be so for some time, tankage may be more accessible than would be the case under three-plant operation. While existing methanol storage capacity is not co-located with existing power generation plant, a virtual trucking-based methanol pipeline could be established similarly to what already exists to transport other domestic fuels such as petrol, diesel and LPG. Relocating generating plant so that it is co-located with methanol tankage is also a potentially feasible option, particularly when integrated with unutilised pipeline capacity between point sources of methanol storage and potential plant relocation sites.

Disadvantages

Of disadvantages, the clearest is that none of the existing thermal power generating plants in NZ are currently able to accept methanol as fuel. However, the process of

Box 12: Israel Electricity Corporation power plant methanol conversions

The Israeli Electricity Company (IEC) owns 15 power generation sites across Israel, some of which burned HFO and diesel. To comply with air pollution regulations and enable unconstrained operations, IEC cooperated with Dor Chemicals, a methanol importer, to enable the dual-firing of methanol with incumbent heavy fuel oil (HFO) at a 140 MW boiler unit in Haifa and the full conversion of a 50 MW OCGT in Eilat from diesel to methanol. The Eilat OCGT is a Pratt & Whitney FT4C Twin Pac installed in the 1970s and was not designed to burn methanol. To facilitate the conversions fuel pumps, nozzles, and atomisers had to be added or modified to enable the higher flow rate of fuel required given that methanol has only half the volumetric energy density of diesel. Methanol storage tanks and new fire detection and fighting systems also had to be added. In Eilat, this included a 2,000 m^3 tank with a floating roof to suppress methanol evaporation, infra-red sensors capable of detecting any invisible flames of a methanol fire and alcohol resistant foams to fight any possible fire.

While the Eilat turbine still requires diesel during plant start-up and ramp-down phases, the conversion is considered a success in delivering lower maintenance costs and higher power outputs due to methanol's cleaner burn and lower air-to-fuel ratios. While a test phase was required the entire conversion cost only US$5m and was executed across two years (2012 and 2013) and has demonstrated that the conversion of turbines to run on methanol is not only possible but can be executed at relatively low capital cost. The resulting reductions in emissions include a 18%, 41%, and 44% reduction in NO_x, SO_x and particulates at the Haifa power station, respectively, while the OCGT in Eilat achieved reductions of 76%, 90% and 100%.

The Eilat gas turbine unit as seen from the top of the methanol storage tank converting plant to accept methanol in place of other fuels such as diesel and gas is in many cases straight forward. An example is in Eilat, Israel, where to comply with local air pollution standards a 50 MW OCGT turbine was converted from diesel to operate on methanol. The conversion process cost US$5m including the construction of a small onsite methanol tank.

The most significant operational disadvantage of methanol as a generation fuel is efficiency and cost. At a OCGT heat rate of 12-13 GJ/MWh methanol's fuel efficiency is around one-third lower than the 8-9 GJ/MWh of gas. In addition, more than one-third of the calorific value of the natural gas that goes into methanol production is lost as heat during the conversion process, increasing overall wellhead-to-electron emissions. Of some offset is that methanol is as clean as natural gas in particulate emissions such as NO_x and SO_x. Methanol also burns relatively cold which reduces the thermal shock on plant which improves start up and ramp times.

Another potential disadvantage is that methanol pricing is set to international market conditions and drivers, particularly oil price, which would likely shift the focus of marginal generation fuel pricing away from the domestic gas market and towards international commodity markets. This is however no different than is already the case with other fuels already consumed in NZ including petrol, diesel, aviation fuel, LPG and coal.

Potential NZ conversions and cost

An initial review of existing thermal generating plant operating in NZ (Table 1) indicates that conversion to methanol is likely to be viable in at least some cases. The clearest example is the Stratford OCGT units which operate GE LMS100 turbines which are certified to accept more than 20 fuels, including methanol. The modifications required to accept methanol in place of gas would be relatively minor and we expect materially less expensive than was the case at Eilat, which has Pratt & Whitney turbines. Whirinaki, which is configured to operate on diesel, could also be a viable conversion candidate.

By far the biggest cost involved with converting generating plant to methanol would be storage, if new storage is required. While there is evidence to suggest that methanol storage tanks can be built inexpensively with low sophistication, it is likely that the design concept would require a more sophisticated facility to store methanol for long periods with a floating roof to suppress methanol evaporation, similar to LNG boil-off. This would be similar in design to other refined fuel storage facilities already operating at various fuel terminals around NZ.

Indicatively, to build storage able to hold 10 PJ of methanol could we estimate cost between $437m and $533m. In a best case scenario, where the facility was able to operate through to 2050, we calculate a CRF fee of $67m pa at a 10% WACC.

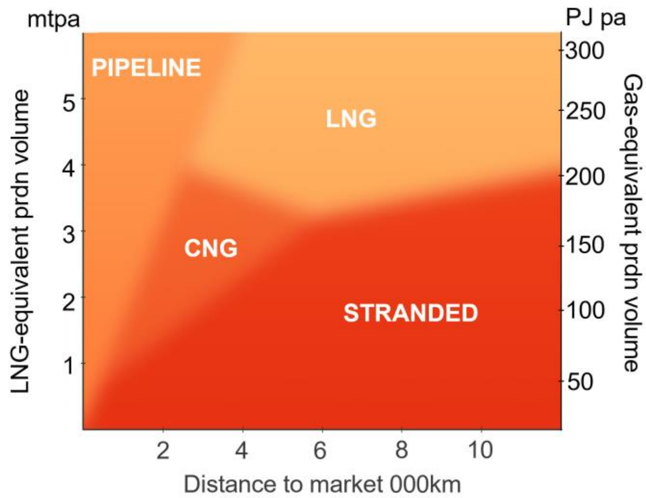
CNG

CNG typically refers to gas that is pressurised to between 2,900 and 4,300 psi (200-290 bar) and is stored at ambient temperature. This is as opposed to LNG which is stored at ambient pressure but at colder temperatures. CNG typically delivers an energy density between one-sixth and one-third that of LNG however it does not require the sophisticated liquefaction and regasification equipment to enable its handling and storage. Instead, its handling only requires storage in pressurised vessels which, as they are not insulated, typically has a much lower capex profile for smaller volumes than equivalent LNG solutions. A significant drawback however is that CNG storage vessels can explode if mishandled.

Low relative capex but also low relative energy density means that CNG currently tends to be viable only in a narrow niche of low distance/duration and low volume requirements where pipeline or LNG options are not typically viable (Figure 41). As a grid-scale gas storage option, the penetration of CNG is much lower than for UGS and LNG and has been falling. The UK previously maintained a handful of CNG storage facilities to meet peak demand in urban areas, some capable of storing up to 15 TJ of gas, however by the late 1990s these had been decommissioned as more flexible and larger scale solutions such as UGS, LNG imports and pipeline interconnections with Europe have been brought to market.

Today, CNG storage solutions are still used but typically by individual users where their gas grid connections cannot meet their maximum demand loads. Data from Wartsila comparing CNG to LNG for peak shaving duties at gas-fired power plants suggests that CNG is best suited to storing no more than a few dozen TJs for release to the grid over a few hours or smaller amounts to be stored and released over several days.

Figure 41: Gas commercialisation pathways



Note: Representation is on a standalone point-to-point basis.

Source: Enerlytica

Similarly to LNG and LPG, CNG can serve to support the development of virtual pipelines. Road transport of CNG in volumes equivalent to 0.4-0.5 TJ for industrial use have operated for several decades, however it is relatively uncommon outside of regions with plentiful, cheap gas (such as Iran and the US) and outside of use cases that are off-grid (such as mining) or which are temporarily disconnected or restricted from the grid (such as during pipeline maintenance). A relevant OECD example is an operation in the northwest US which relays CNG by road to remote paper mills as a substitute for diesel. Reports suggest that the cost of delivering gas by road in the form of CNG can add the equivalent of $7-14 per GJ for delivery distances of between 250 to 1,000 miles.

The only known example of where CNG is transported in bulk by sea is in Indonesia where a CNG carrier transports 27 TJ of gas 500km from Java to Lombok to fuel a gas-fired peaking power plant. While CNG marine transport solutions are coming into the spotlight as new storage technologies are advanced, it is challenged by the increasing ubiquity of LNG facilities. Given its high relative costs and comparatively low uptake elsewhere in the world, we expect CNG would only be viable in NZ in a very small number of site-specific cases as a peak shaving solution for smaller individual gas customers, rather than for grid scale applications. One potential such case may be the Whirinaki power station which due in part to low gas pipeline capacity maintains a sizeable onsite inventory of diesel. Indicatively, using industry benchmarks we estimate that the cost of a CNG facility scoped to store 10 PJ would likely exceed $18 bln in cost and is therefore highly unlikely to prove feasible against other large-scale storage options.

LPG

NZ has a mature LPG market including an established network of domestic supply channels and handling infrastructure. Under NZS5442 (the NZ standard for reticulated natural gas), gas that is permitted to be injected into the reticulation system (which principally comprises methane and ethane) can comprise cuts of both propane and butane. There is therefore scope to consider whether LPG production, storage and/or handling infrastructure could be extended towards assisting with managing gas market constraints.

LPG is typically produced by one of two means; either it is separated from the gas stream in a gas processing plant or it is cracked from crude during the oil refining process. Although cracked LPG makes up close to half of global LPG production, NZ's only refinery at Marsden Point did not crack LPG while it was operating. All locally produced LPG is therefore sourced via separation of gas streams at plants that have LPG fractionation cycles.

There are six gas plants that operate in NZ which can separate LPG (Figure 43). These six plants operate under one of two technical configurations:

1. **Standalone fractionation**: Where LPG is separated as part of the raw gas treatment process. Maui, Kapuni, Rimu/Kauri/Manutahi (RKM), Kupe and Waihapa each operate to this format. Of these, Kupe, Maui and Kapuni operate at comparatively high utilisation, RKM operates at low utilisation and Waihapa does not offer sufficient underlying production to enable LPG separation.
2. **Straddle**: Where fractionation is undertaken on rich but still NZS 5442 compliant spec gas to remove remaining LPGs from the stream. Once processed, output gas is lean but still NZS 5442 compliant and injected back as sales gas, while separated LPG is sold as standalone product. Todd Energy's McKee LPG plant integrated with its existing McKee gas plant was (and remains) the local market's first straddle plant. When operating it receives comingled spec gas from Todd's Mangahewa, McKee and Pohokura equity gas entitlement streams from which it separates LPGs with the post-separation gas stream then used either onsite into power generation or exported to commercial gas customers. It is therefore more accurate to think of LPG produced from the McKee straddle plant as McKee+Mangahewa +Pohokura (MMP) LPG. While it ran at high capacity during its first few years of operation after it entered production in 2012, utilisation fell sharply following the sale by Todd Energy of its Nova Energy LPG

Figure 42: NZ LPG separation plants

Plant	Operator	Plant type	Production			Storage onsite	Known oftake customers
			Start Year	Capacity ktpa	2022 kt	tonnes	
Kapuni	Todd Energy	Integrated	1970	55	29	400	Vector
Maui	OMV	Integrated	1979	185	20	1,900	Elgas
Waihapa	NZEC	Integrated	1996	115	-	250	n.a.
RKM	Westside	Integrated	2002	35	0	550	Vector
Kupe	Kupe JV	Integrated	2009	115	92	2,400	Genesis, Vector
McKee	Todd Energy	Straddle	2012	27	10	320	Vector
					152	**5,820**	

Source: company disclosures, Enerlytica

business to Genesis in 2017. The plant now runs only periodically, reflecting that it has tended to be more valuable for Todd to leave LPG in the gas stream than to separate and market it as a standalone product.

Indigenous LPG production has been on a decline trend since 2014 when it peaked at 238 kt. In 2022 NZ production totalled 152 kt. With North Island demand of 98 kt in 2022, wholesale sellers were therefore required to move 54 kt out of the North Island principally to the South Island. The 40 kt supply balance required to meet South Island demand was imported from the Australian East Coast which serves as the 'next-best' source alternative for NZ buyers (Figure 43). LPG traded from there is indexed at or near the Saudi Aramco Contract Price (Saudi CP), which is the dominant LPG pricing benchmark in the Asia-Pacific region.

Until COVID, the demand trend over the prior decade had been one of strong growth and strengthening retail competition as suppliers vied for scale and market share. Atop this was a theme of transaction-led retail consolidation and supply chain integration, with the sale by Todd Energy of its Nova Energy LPG business (to Genesis in 2017) and by Contact Energy of its Rockgas LPG business (to First Gas in 2018) being particular examples.

With all indigenous production located in the Taranaki region, a relatively low level of installed system storage (Figure 43) and a strong winter bias to demand (Figure 44), the logistics of managing local market demand with supply are already relatively complex and require careful management to avoid supply disruptions. This is particularly the case during periods of peak winter demand.

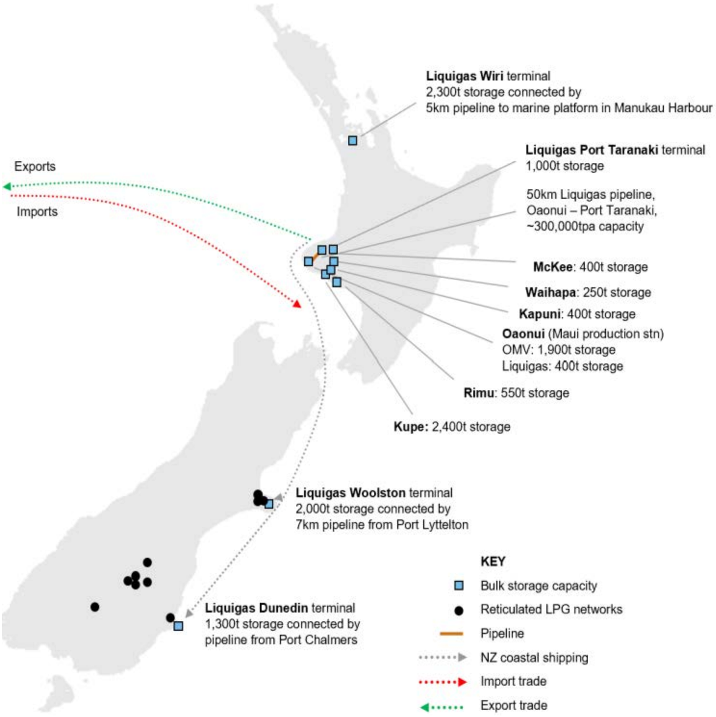
Liquigas

An important midstream LPG agent is Liquigas which owns and operates the bulk handling terminals at three seaports (Taranaki, Lyttelton and Dunedin) as well as dedicated bulk storage facilities at the Maui production station (supported by a 50km direct pipeline connection to Port Taranaki) and at Wiri in South Auckland. Its model is that of a toll operator and it does not assume title of LPG that it carries. Liquigas is majority-owned by Vector (60.25%) with minority stakes held by Elgas (18.75%) with interests associated with First Gas holding the (21.0%) balance.

In addition to operating its handling infrastructure, Liquigas also performs an important market-clearing function by aggregating excess LPG from fields and arranging vessel charters to consign cargoes for shipping.

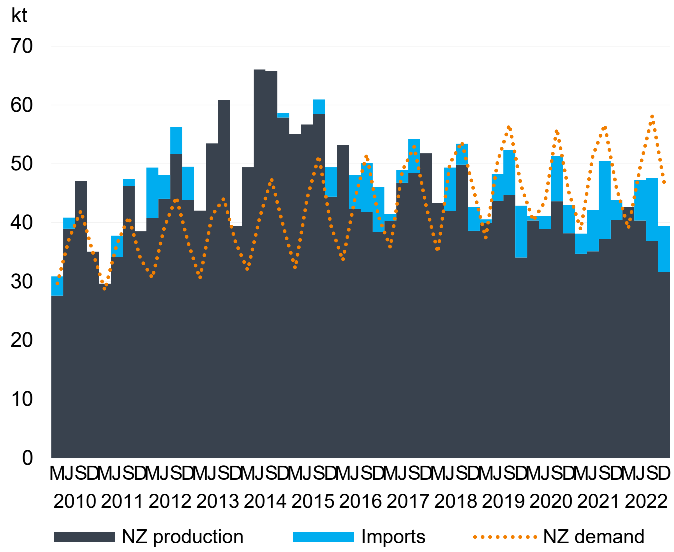
During summer months when LPG market demand is lower but field production profiles remain typically firm Liquigas has historically coordinated export cargoes. Much more common now is for Liquigas to arrange import shipments during peak winter months, principally into the South Island market via its Woolston and Port Otago receiving terminals.

Figure 43: NZ LPG storage & network infrastructure



Source: Enerlytica

Figure 44: NZ LPG production vs trade vs demand



Source: MBIE data, LPGA data, Enerlytica

Capacity headroom

As NZ is already a net-import market (in other words, LPG must be imported to meet local market demand), the question of whether and to what extent there could be capacity to repurpose LPG supply to increase indigenous natural gas availability to help meet local market gas demand has two potential dimensions.

1. **Repurposing of indigenous LPG**

Firstly, there is the question of what volumes of indigenous LPG could feasibly be repurposed to natural gas. This involves making assessments of the levels of technical and commercial flexibility that could be obtained from each of the major producing fields – being Kupe, Maui, Kapuni and MMP – to reduce LPG yields and increase gas yields. The answer will be different for each field and reflect individual gas compositions; for example the ability to repurpose Kupe gas is lower than it is for Maui gas because Kupe feed-in gas is already relatively rich with LPGs which reduces the scope to leave larger cuts of propane and butane in the export gas stream. Maui feed-in gas by contrast is much leaner, providing more flexibility to leave LPG in the gas stream.

Notwithstanding individual field profiles, we expect the case for repurposing indigenous LPG into the gas stream would in aggregate be low as:

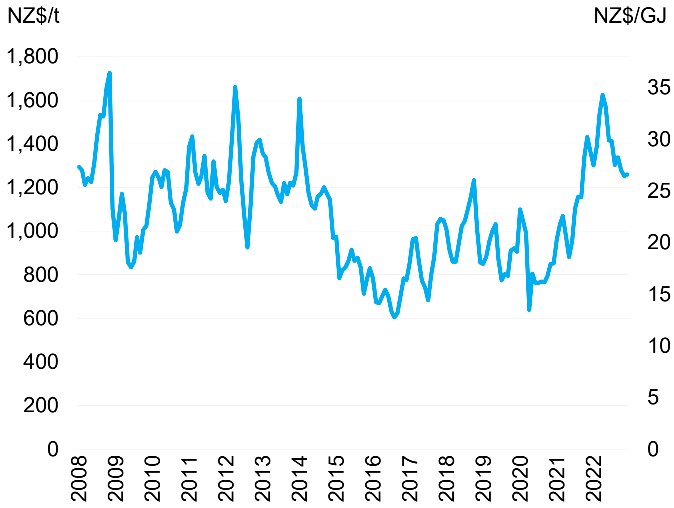
- It would likely lead to logistical difficulties and additional cost to commercial arrangements between buyers and sellers where supply of domestic LPG was prioritised, particularly given the shared peak demand seasonality between LPG and gas.
- Filler LPG would need to be procured from the import market to meet demand at significant additional cost, both financial (to wholesalers) and economic (to NZ net exports).
- The materiality of any repurposing of LPG towards meeting gas shortfall would be relatively low. For example, if half of total Maui LPG production was able to be repurposed to gas (a very large relative quantity in indigenous LPG terms), it would yield only 1 PJ of additional feed-in gas.

2. **Fuel switching**

Another potential route to repurpose LPG in favour of gas could be to physically convert individual users away from gas and towards LPG. While this option would be technically feasible for many gas users, it faces a number of execution difficulties including:

- For users that are connected to the gas network, LPG would likely be a more expensive fuel option, both in terms of capital cost (conversion costs, potentially including the installation of onsite LPG handling and storage infrastructure) and operating cost (on a per unit basis LPG is typically more expensive than natural gas) (Figure 45). For 2022, import parity LPG pricing including estimates for freight and terminal handling costs approximated $28/GJ. Costs to transfer LPG from Port Taranaki to its point-of-use would be additional.
- Given the LPG market's net-import position, marginal LPG volumes would need to be imported at a higher delivered cost than indigenous product, increasing overall system costs.

Figure 45: Saudi CP-based NZ LPG import parity cost



Source: Refinitiv data, Enerlytica

- Materiality would be comparatively low given it would take a relatively large number of gas users to convert to LPG to deliver a material reduction in gas demand.

Factoring these considerations, the potential for LPG to provide material support to the availability of natural gas is in our view low.

LPG for power generation

A specific LPG application that in our view could be considered in more detail for the potential support it could provide to the domestic energy sector is that of LPG to power generation.

LPG-fired powergen has been experiencing solid growth in some international settings, particularly in developing economies and archipelago nations. A major attraction of sourcing LPG compared to LNG is greater diversity of supply given it can be a product of either or both of natural gas and/or oil production. There is also a much wider choice of vessel options ranging from very large (the largest LPG carriers can carry 90,000 m^3 or 44 kt in a single cargo) down to smaller carriers of the type that usually service the NZ market (typically 2-3 kt).

In NZ, LPG powergen could potentially provide the electricity sector with a flexible fuel option that, like coal, is available domestically but which can be sourced from international markets when local supply is insufficient to meet local demand.

LPG also presents a much lighter emissions profile than coal, both on direct (LPG firing produces around half the per-kWh emissions of coal) and indirect (the logistics involved of moving LPG are much less emission-intensive than is the case for coal) measures.

In NZ, Liquigas's existing Wiri marine terminal in the Manukau Harbour could present an ideal site for LPG-fired powergen. The key attractions of the location are its existing infrastructure (the terminal can store up to 2,300 tonnes of LPG and has both road and sea connection options) and location (the site is within the Auckland isthmus as NZ's largest locational source of baseload and peak electricity demand).

Further investigation of site specifics would be required to enable a detailed assessment of the feasibility of the site for powergen, in particular to understand the availability of transmission capacity sufficient to enable the export of high voltage power into the grid, the availability of suitable sites to house generating plant and consenting issues associated with site options.

Depending on these assessments, site selection for generating plant has multiple potential options including:

i. **Onshore relocation –** Moving existing plant from its existing location to an onshore site nearby to the Wiri terminal. Potential such candidates could include one or both of the SPS OCGTs or Whirinaki.

ii. **Onshore new build –** Adding new plant to an onshore site nearby to the Wiri terminal.

iii. **Offshore –** Adding seaborne (eg barge-mounted) plant to an offshore site located near the existing marine platform.

While in absolute terms the Wiri terminal's storage capacity is relatively small (2,300 tonnes is equivalent to only 115 TJ), in relative terms it could prove material depending on the expected extent and shape of powergen demand. For example, assuming a 100 MW OCGT with a heat rate of 8.9 TJ/GWh infers a full-to-empty fuel storage equivalent to 15 days assuming the plant operates only during peak demand periods (7-11am and 5-9pm).

There may also be potential for expansion options that could enable LPG supply and generation capacity into Wiri to be extended by adding floating storage to integrate with the existing sea-side marine platform and shore-side terminal. Past seaborne loadings into Wiri have tended to involve cargoes of ~2,000 tonnes which if used as floating storage could nearly double the storage capacity already available onshore at Wiri.

Indeed, offshore storage could feasibly be stacked to provide a near-continuous supply of LPG to a powergen installation. In the case of an onshore installation the extent to which supply could meet demand would rely on the maximum throughput capacity of the onshore terminal. Indicatively however, assuming an extreme scenario under which logistics could enable daily cycling of full terminal handling capacity, 2,300 tpd of feed-in could support up to 480 MW of OCGT if operated baseload or as much as 1,430 MW if operated only during peak.

Based on international LPG powergen analogues, we estimate that the cost of installing LPG capable power generation as likely to range between $2.0m and $4.8m per MW. With the higher bound likely to include the cost of installing LPG storage and handling infrastructure, we expect the cost of an installation at Wiri would be closer to the lower end bound given that onsite storage already exists. To locate 100 MW of peaking power generation, we therefore estimate a best case cost of just over $200m with an inferred CRF of between $27m-$65m pa depending on whether the facility is assumed to operate to 2050 or is limited to 2030.

4.2 Option screening

We have compared the relative cost profiles of above ground and below ground gas storage options (Table 13). These projects include expanding the Ahuroa UGS facility, converting Tariki into a UGS facility, developing a CNG gas storage facility and developing a domestic LNG gas storage facility. For the purposes of this comparison we have sized the latter two of these projects to match our Tariki UGS conversion case. To enable comparison we have also included our 'best fit' Port Taranaki LNG import concept in the screen.

The major conclusions are:

- A shared challenge with any domestic storage-only option is a reliance on being able to access the excess indigenous gas that would be required to charge and draw-down storage as it is needed.
- Given that domestic gas storage projects would be developed primarily to serve the thermal generation sector and may only be required out to 2030, inferred costs are high as project owners will need to make a return within this comparatively short horizon.
- If the market did have sufficient domestic gas to enable unconstrained cycling then UGS options present as the most cost-effective solutions. While we have opted not to evaluate other options such as an expansion of Ahuroa, conversion of Tariki would deliver both additional flexibility and capacity at a CRF of between $215-395/GJ.MDQ with a project end date of 2030 and $104-161/GJ.MDQ with a project end date of 2050.
- With above-ground options, CNG cannot deliver the necessary scale and is prohibitively expensive. A domestic LNG or methanol storage facility provides the most credible gas storage alternatives to UGS, however at more than $28,700/GJ.MDQ for a best case LNG storage option with a timeline to 2050, it would be orders of magnitude more expensive than a UGS option. A best case new build methanol storage option to 2050 is more competitive at $624/GJ.MDQ but is still double the cost of Tariki with a project end date of 2030 and suffers from the reality that the energy it supplies cannot be used as efficiently as natural gas. Being able to access existing methanol storage would significantly reduce this cost compared to a new build scenario.

- When domestic options are set against a LNG import option with a project end date of 2050, UGS still presents as the least expensive with a CRF on an electricity basis of $0.9m/GWh.MDQ. By comparison, the equivalent CRF for an LNG import project at Port Taranaki and a methanol storage concept compute at $2.1m/GWh.MDQ and $7.6m/GWh.MDQ respectively while a domestic LNG storage project is $86m/GWh.MDQ. Of all the options, UGS at Tariki would likely be the fastest to bring new storage to the market while an LNG import project would not we expect be far behind and could also bring the benefit of new commodity (rather than just storage) and suppliers.

Table 17: Comparison of potential gas and energy storage projects, assuming best case economics

	Unit	Tariki	LNG as domestic gas storage	Methanol as domestic storage	LNG import
Gross energy storage capacity	PJ	10	10	10	164
Capex (Best case)	NZ$m	62	5,360	503	140
Capex per PJ of storage capacity	NZ$m/PJ	6	536	50	1
Time to develop (Best Case)	Years	1	3	2	1
MDQ (Gross energy basis)	GJ	75,000	75,000	106,500	500,000
MDQ (Net electricity basis)	GWh	8	8	9	56
CRF - 2030 close	NZ$m/GWh	1.9	256.3	18.9	2.5
CRF - 2040 close	NZ$m/GWh	1.1	106.1	9,.3	2.2
CRF - 2050 close	NZ$m/GWh	0.9	86.7	7.8	2.1

Source: Enerlytica

GLOSSARY

2P	proved and probable petroleum reserves, also referred to as P50 reserves
appraisal well	a well drilled to determine the size of an oil or gas discovery
associated gas	gas that is produced in association with oil or condensate and separated in the production process
baseload	electricity generation plant used to meet some or all of continuous electricity demand, and produce at a constant rate, usually at a low-cost relative to other generation options available to the system
bbl	barrel, equal to 42 US gallons or 158.987 litres
Brent crude	a major oil marker price for sweet light crude oil and the leading global price benchmark for Atlantic basin crude oils. Almost 70% of the world's internationally traded crude, including most New Zealand crude, is priced against a Brent crude benchmark.
CAGR	compound annual growth rate
capex	capital expenditure
CCGT	combined cycle gas turbine
CIF	cost, insurance and freight
CNG	compressed natural gas, being natural gas that has been compressed or contained under pressure
CO_2	carbon dioxide
condensate	light hydrocarbon compounds of low density and high API gravity that normally exist in a reservoir as gas but condense to a liquid during production
CRF	capacity reservation fee
crude	see *oil*
D&A	depreciation and amortisation
DCF	discounted cash flow
DES	delivered ex-ship
development well	a well drilled to enable production from a known oil or gas reservoir or deposit
EA	Electricity Authority
EOR	enhanced oil recovery
E&P	exploration and production
EPC	engineer, procure, construct
ETS	emissions trading scheme
exploration well	a well drilled seeking new, undiscovered petroleum deposits
FCE	Fletcher Challenge Energy
FCF	free cash flows
FID	final investment decision, being the decision point at which a venture's sponsors give their commitment to sanction and develop the venture
FLNG	floating LNG
FOB	free on board
FPSO	floating production, storage and offloading vessel
gas	a naturally occurring hydrocarbon consisting primarily of methane
GDP	gross domestic product
GIC	Gas Industry Company
GJ	gigajoule (10^9 joules)
GJ.MDQ	per gigajoule of maximum daily quantity
GSA	gas sale agreement
GWh	gigawatt hour
HH	Henry Hub gas price
HPDI	high pressure direct injection
hydrocarbons	an organic compound consisting entirely of hydrogen and carbon, the majority of natural variations of which occur in crude oil
I&C	industrial and commercial
IGU	International Gas Union
IMO	International Maritime Organization
IRR	internal rate of return
JKM	Japan Korea marker price
Joule	a unit of energy, equal to 1/3600 of a kWh
JV	joint venture

km^2	square kilometres
kt	thousand tonnes
ktpa	thousand tonnes per annum
kWh	kilowatt hour
Line pack	the amount of gas that stored within transmission and distribution systems at a specific point in time
LNG	liquefied natural gas
LPG	liquefied petroleum gas, being mainly propane (C_3) or butane (C_4) or a mixture of both
LRMC	long run marginal cost
m	million
MBIE	Ministry of Business, Innovation and Employment
MDQ	maximum daily quantity
methanol	methyl alcohol (CH_3OH), a colourless liquid produced from natural gas and is the raw material for many chemicals, formaldehyde, dimethyl terephthalate
mmboe	million barrels of oil equivalent
mmbtu	million British thermal units
mt	million tonnes
mtpa	million tonnes per annum
MW	megawatt (10^6 watts)
natural gas	a term most commonly used to describe gas that meets specification standards to be injected into a pipeline for reticulation to end users. In New Zealand, the specification for reticulated natural gas is set out in national standard NZS 5442
NOC	National Oil Company
NPV	net present value
NZP&M	New Zealand Petroleum and Minerals, a division of MBIE responsible for administering the Crown's oil, gas, minerals and coal resources
OATIS	Open Access Transmission Information System, the pipeline operation system which facilitates third party access to the Maui Pipeline
OCGT	open cycle gas turbine
oil	a generic term to describe oil products in various forms including crude oil, condensate and naphtha. In this report the term *oil* is used interchangeably with *condensate* and *crude*
opex	operating expenditure
pa	per annum
peaking plant	electricity generation plant operated expressly for the purpose of providing electricity into the market during periods of peak demand, usually at a higher cost relative to other generation options available to the system
PHS	pumped hydro scheme
PJ	petajoule (10^{15} joules)
PJe	petajoules-equivalent
PPA	power purchase agreement
reserves	the portion of PIIP that is at a specified date economic to develop and extract under a given set of technical, commercial and economic assumptions
resource	the portion of PIIP that is not economic to develop and extract under the same assumption set.
SI	spark injection
SPA	sale and purchase agreement
SPS	Stratford Power Station, comprising TCC CCGT and two OCGTs operated by Contact Energy
SRMC	short run marginal cost
ROI	return on investment
T	tonnes
TCC	Taranaki Combined Cycle power plant, owned and operated by Contact Energy at its SPS
TJ	terajoule (10^{12} joules)
TJe	terajoules-equivalent
tpa	tonnes per annum
tpd	tonnes per day
UGS	underground gas storage
US$	United States dollars
VWAP	volume weighted average share price
WACC	weighted average cost of capital

CONVERSIONS

OIL

1 mmbbl of crude equals	6.29	million m^3
	178.08	bcf
	1.00	mmboe
	0.15	mtoe
1 PJ of crude equals	21.27	kt
1 tonne of crude equals	6.85	bbl

GAS

1 PJ of gas equals	0.16	mmboe
	38.81	million m^3
	0.91	bcf
	947.82	billion btu
1 btu of gas equals	1.055	KJ

LNG

1 tonne of LNG equals	13.8	bbl
	2.2	m^3
	55	GJ
	9	boe

LPG

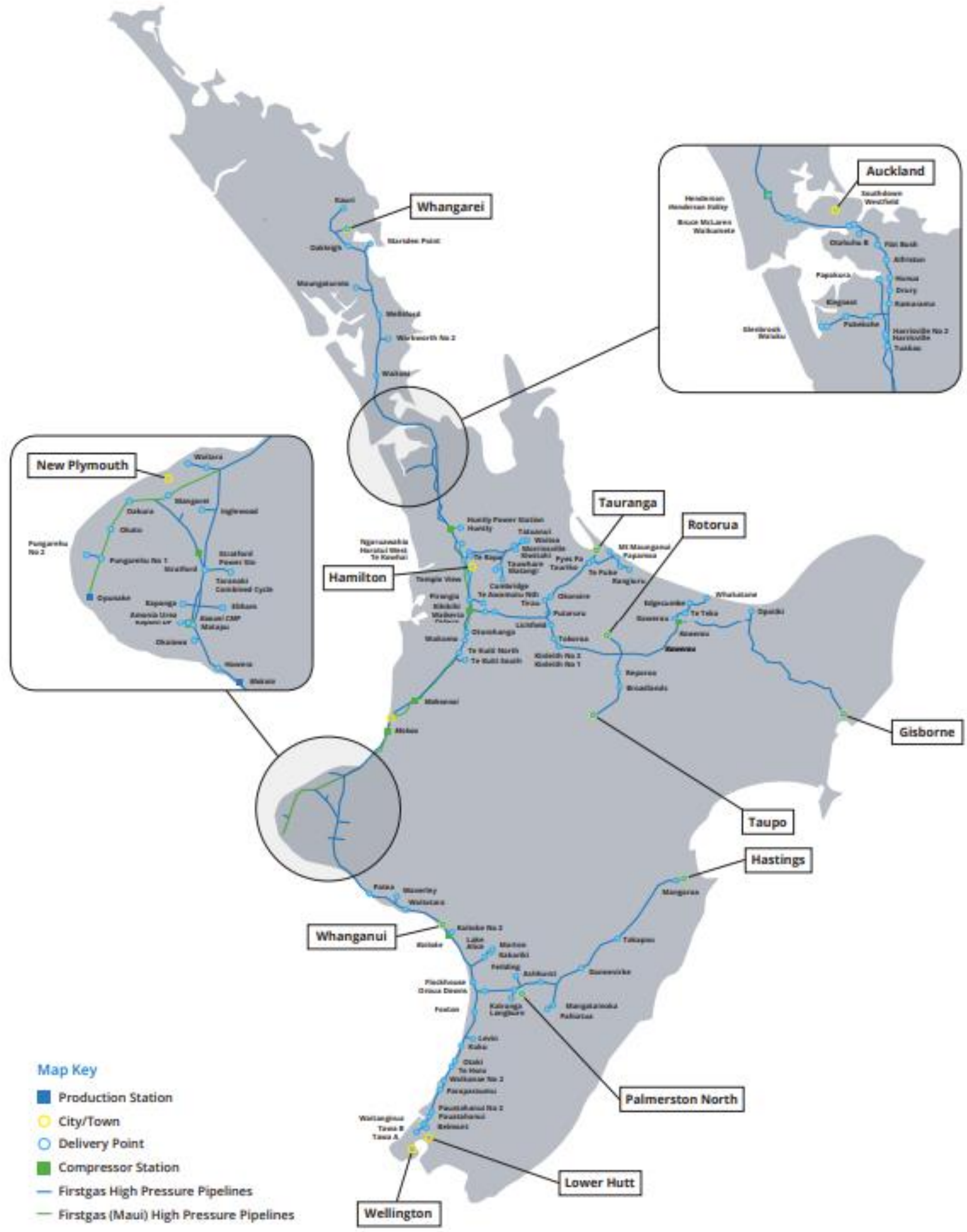
1 tonne of LPG equals	11.78	bbl
	1.87	m^3
	49.7	GJ
	8.15	boe

VOLUME

1 cubic metre equals	35.31	ft^3
1 barrel of oil equals	0.16	m^3
	5.61	ft^3
	159	litres

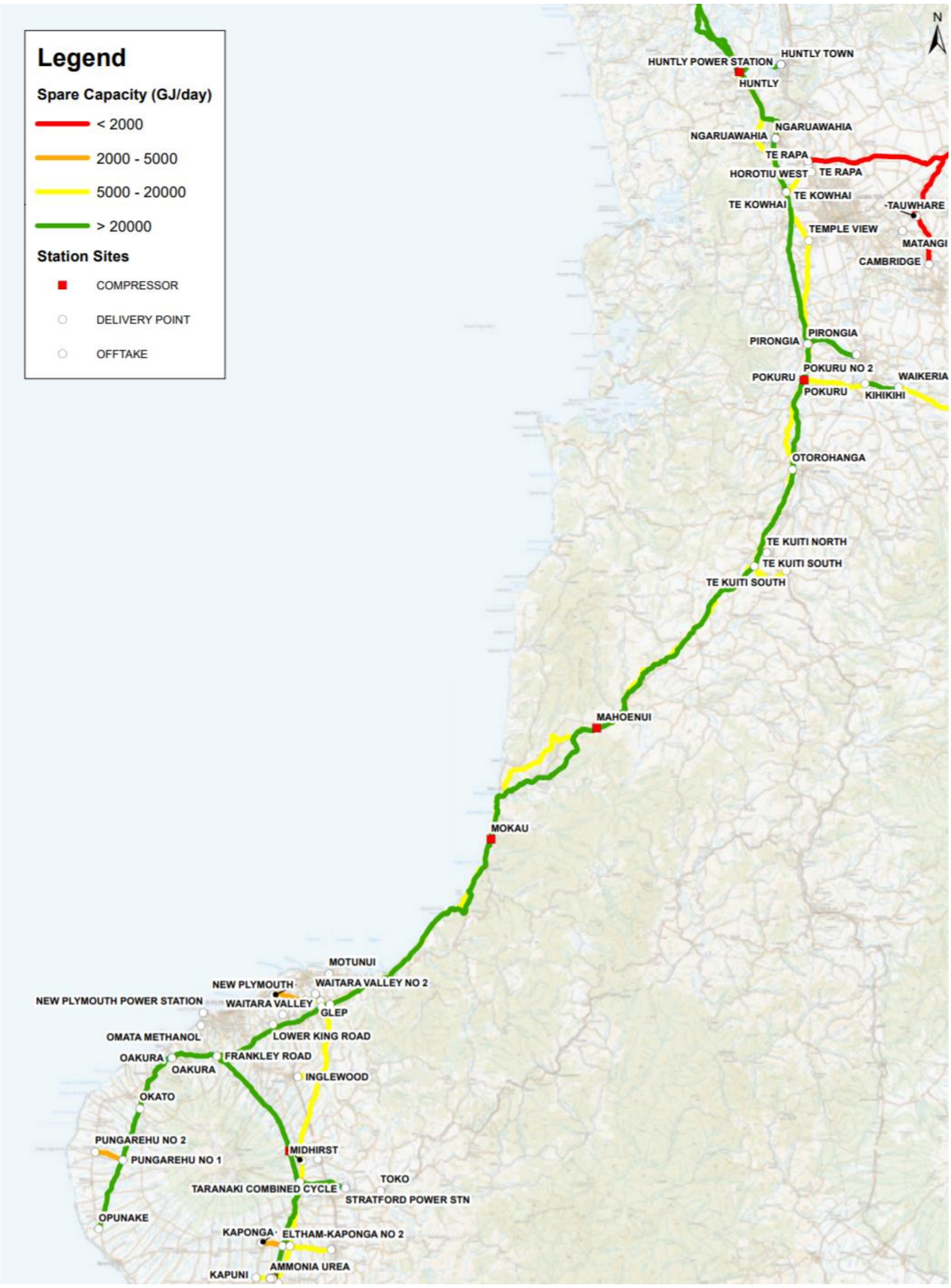
GAS TRANSMISSION NETWORK

High pressure gas transmission network



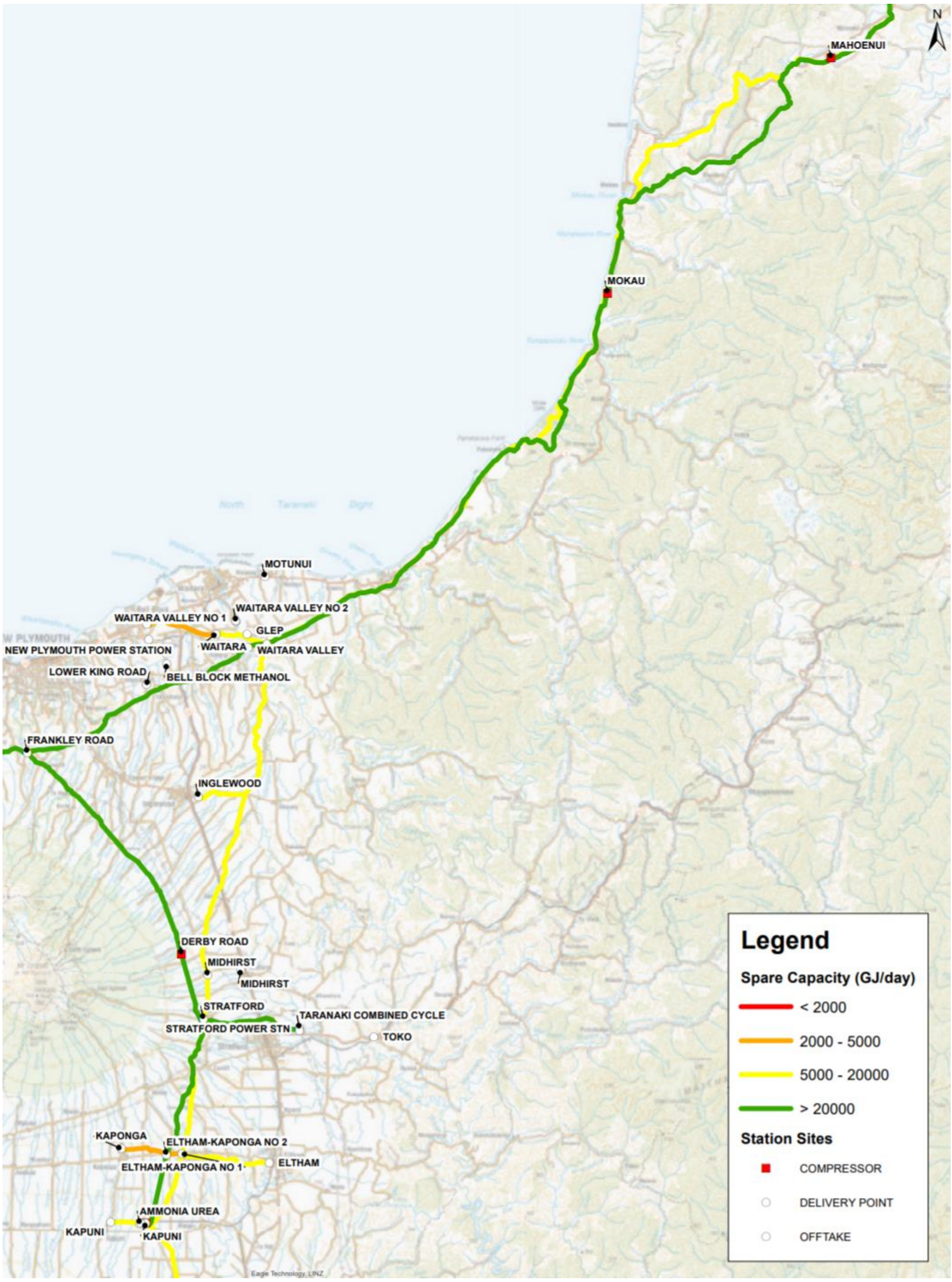
Source: First Gas

Transmission pipeline capacity – Maui System



Source: First Gas

Transmission pipeline capacity – Central South System

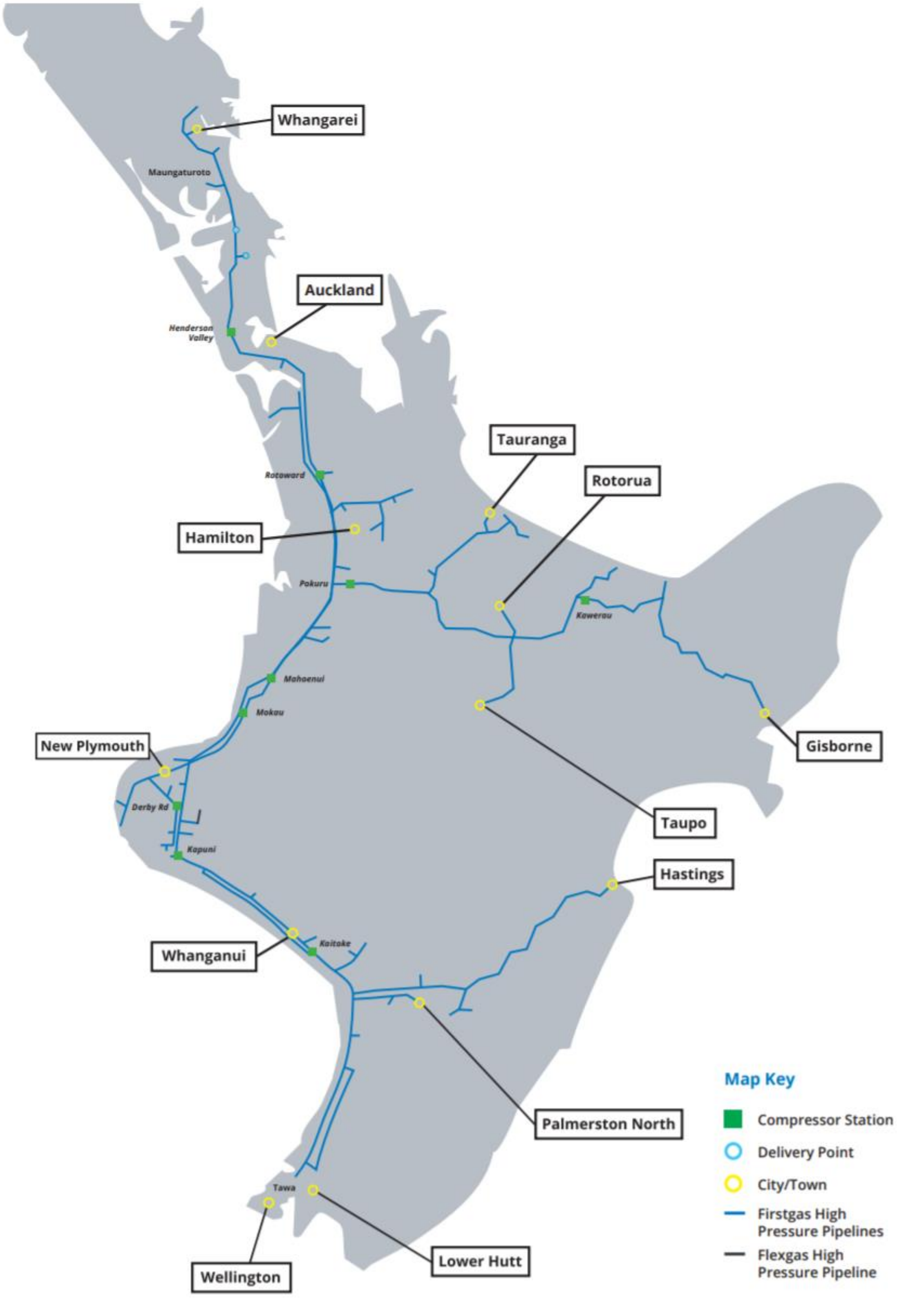


Source: First Gas

Transmission pipeline capacity – Northern System

Source: First Gas

Compressor stations



Source: First Gas

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