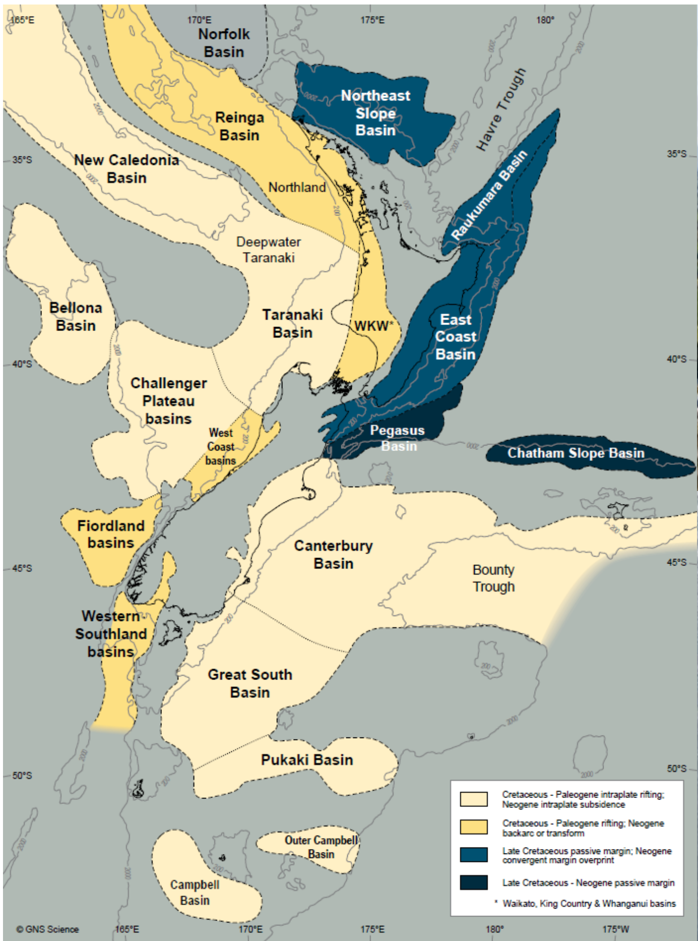
www.concept.co.nz





Long term gas supply and demand scenarios – 2016 update

5 October 2016

About Concept

Concept Consulting Group Ltd (Concept) specialises in providing analysis and advice on energy-related issues. Since its formation in 1999, the firm's personnel have advised clients in New Zealand, Australia, the wider Asia-Pacific region, and Europe. Clients have included energy users, regulators, energy suppliers, governments, and international agencies.

Concept has undertaken a wide range of assignments, providing advice on market design and development issues, forecasting services, technical evaluations, regulatory analysis, and expert evidence.

Further information about Concept can be found at www.concept.co.nz.

Disclaimer

While Concept has used its best professional judgement in compiling this report, Concept and its staff shall not, and do not, accept any liability for errors or omissions in this report or for any consequences of reliance on its content, conclusions or any material, correspondence of any form or discussions, arising out of or associated with its preparation.

No part of this report may be published without prior written approval of Concept.

Acknowledgement

The authors wish to thank the individuals and organisations that participated in interviews with staff from Concept and the Gas Industry Co as part of this project. The information provided by these organisations was extremely useful as a supplement to published data sources.

Contents

Executive summary 5
1 Purpose and structure of report 16
1.1 Purpose 16
1.2 Structure of this report 16
1.3 Relationship with earlier reports 17
2 Market Scenarios 18
2.1 Purpose 18
2.2 Possible market states 18
2.3 Medium-term market outlook (< 5 years) 20
2.3.1 Longer-term market outlook (5+ years).... 21
3 Gas supply 23
3.1 Purpose 24
3.2 Historical development of gas supply 24
3.3 Current gas production 30
3.4 Gas reserves and contingent resources 32
3.4.1 Gas reserves 33
3.4.2 Reserves to production ratio 35
3.4.3 Contingent resources 36
3.5 Outlook for gas supply 38
3.5.1 Oil price outlook affects gas supply 38
3.5.2 Demand for gas within New Zealand 42
3.6 Greenhouse gas emissions.... 43
3.6.1 CO_2 implications on direct use of gas for energy 44
3.6.2 CO_2 implications of demand for gas for power generation 46
3.6.3 CO_2 implications on petrochemical demand 46
3.6.4 Broader CO_2 implications on upstream exploration 46
4 Gas demand for petrochemical production.... 47
4.1 Purpose 48
4.2 Methanol.... 48
4.2.1 Gas demand outlook for methanol production 50
4.3 Gas demand for ammonia urea production – history and outlook 55
4.4 Petrochemical gas demand projections – summary.... 57
5 Gas demand for power generation.... 59
5.1 Purpose 60
5.2 Types of gas demand for power generation 60
5.3 Historical drivers of gas demand for power generation 61
5.3.1 Variation in renewable generation 62

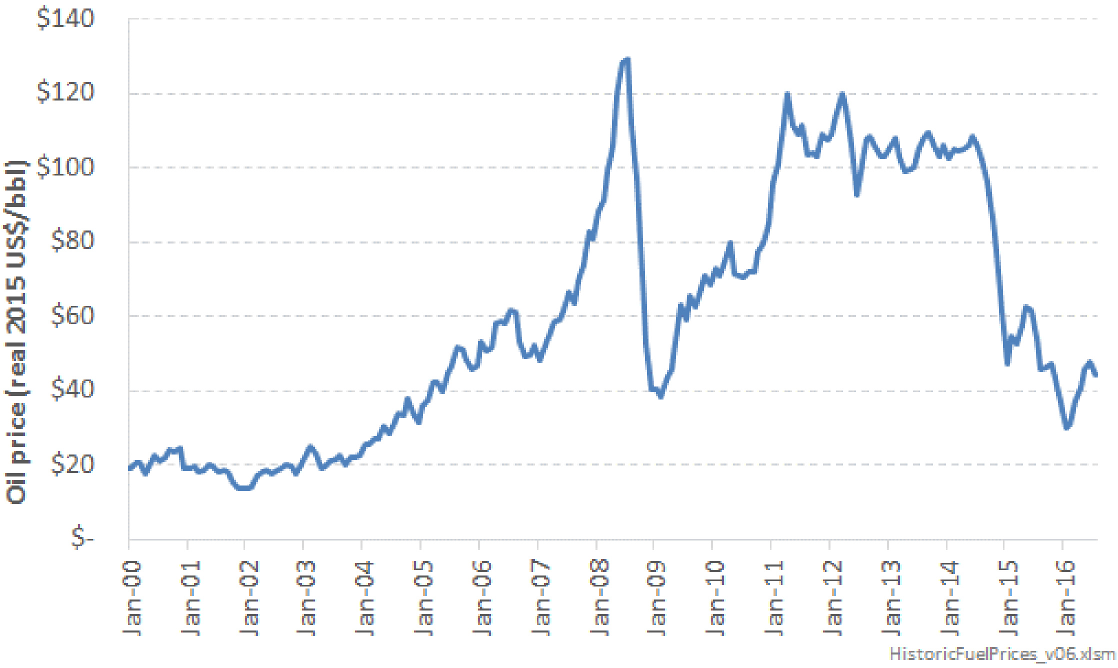
5.3.2 Variations in electricity demand ... 65
5.3.3 Changes in the relative competitiveness between types of power stations ... 66
5.4 Projections of gas demand for power generation ... 69
5.4.1 Central projection ... 70
5.4.2 Sensitivity case - full closure of Tiwai smelter ... 72
5.4.3 Sensitivity case - closure of the Huntly Rankine units (Tiwai remains open) ... 75
5.4.4 CO_2 price sensitivities ... 77
5.4.5 Gas price sensitivities ... 79
5.4.6 Overall range of projected demand for gas for power generation ... 83
5.4.7 Effect of hydrology variation on gas demand for power generation ... 84
6 Direct use - industrial, commercial and residential demand ... 86
6.1 Purpose ... 87
6.2 Historical movements in demand ... 87
6.2.1 Analysis of MBIE data ... 87
6.2.2 Analysis of transmission pipeline gate-station data ... 90
6.2.3 Analysis of Commerce Commission disclosures ... 93
6.3 Projections of demand ... 94
6.3.1 Distribution network projections ... 94
6.3.2 Transmission network projections ... 99
7 Summary projections of demand ... 105
7.1 Purpose ... 105
7.2 National gas demand projections ... 105
Appendix A. Future gas supply options ... 110
Conventional gas - Taranaki basin ... 110
Conventional gas - ex-Taranaki basin ... 110
Unconventional gas ... 112
Potential for gas importation ... 113
Appendix B. Information on wholesale gas prices ... 114
Data from MBIE disclosures ... 114
Contract prices ... 115
Spot gas prices ... 116
Appendix C. Approach to developing distribution network demand projections ... 117

Executive summary

Key observations in a nutshell

For most of the last decade, New Zealand's gas sector has enjoyed a strong tailwind from high oil prices. That tailwind has supported high levels of upstream exploration and development activity – benefiting New Zealand's gas sector because oil and gas have typically been found together in this country. Growing gas supplies over recent years in turn have enabled a step change in gas demand for petrochemical production, while simultaneously allowing New Zealand to maintain or improve its gas inventory position.

Figure 1: Historical world oil prices



As shown in Figure 1, since 2014, the oil price tailwind has died to a weak and erratic breeze. Upstream producers have responded by slashing their exploration and development budgets. This is tightening gas supplies – and has been reflected in a downward revision of official gas reserves.

New Zealand's identified gas sources provide a buffer to support existing rates of use (including petrochemicals) in the short-to-medium term. However, renewed upstream development effort will be needed to replenish gas inventories in the medium-to-long term. The outlook for oil prices will be a key driver in this respect. No one knows if recent oil price weakness is an aberration, or a sign of the future. If the oil price recovers, that will support upstream activity and assist in rebuilding gas inventories. Conversely, if the oil price outlook remains weak, upstream activity will be subdued, putting upward pressure on gas prices. At some point that will inevitably trigger a significant scaling back of demand from petrochemicals and (to a lesser extent) power generation and, in so doing, conserve supply for higher value gas users.

Another influence on the sector is the increasing international focus on greenhouse gas emissions. While global energy demand will progressively shift away from carbon-intensive power generation, paradoxically, gas may obtain some benefit internationally in the next couple of decades. This is because of gas's role as a 'transition' fuel[1] in the power generation sector, enabling switching away from

[1] It is referred to as a 'transition' fuel as it is expected that these gas-fired stations will themselves be displaced in a couple of decades once technology advances enable renewables to cost-effectively displace these gas-fired power stations – particularly from medium-to-high capacity factor duties.

coal-fired power stations to gas-fired turbines which can emit between one-third to one-half the amount of carbon per unit of electricity output (depending on the relative efficiency of the stations).

However, in New Zealand there is limited upside for power generation gas demand from this factor because most of our coal-fired generation has already been displaced, and our abundant renewable options are cheaper than in most other countries. Indeed, our modelling indicates that rising New Zealand CO_2 prices will likely result in some further displacement of gas-fired power generation by renewables over time.

Gas demand for the power generation sector is likely to be by far the most sensitive to variations in New Zealand CO_2 price, with petrochemical gas demand being largely insensitive to New Zealand CO_2 prices[2]. Gas demand for the 'direct-use' residential, commercial and industrial sectors is likely to respond to New Zealand CO_2 prices with a significant lag – and potentially with some inverse correlation in some sectors due to some coal-fired industrial process heat switching to gas in response to higher New Zealand CO_2 prices (and vice versa for scenarios with low New Zealand CO_2 prices).

More generally, higher *international* CO_2 prices would likely to result in increased international gas demand over the next 10-20 years as this encourages switching away from coal to gas-fired power generation (and also – to the extent that higher international CO_2 prices apply to the production of petrochemicals – switching from coal-based to gas-based petrochemical production). This higher international gas demand should generally increase international gas prices. That in turn will tend to improve the relative economics of petrochemical production in New Zealand versus overseas locations for gas-based petrochemical production, which will also tend to encourage local upstream activity.

The future of the Tiwai smelter also has an important influence on the outlook for gas demand. If the smelter were to close or cut production, that would significantly reduce total power demand. That in turn would lower electricity generation requirements, with the bulk of the reduction likely to be from gas-fired power stations. In turn, this would improve New Zealand's reserves-to-production ratio, postponing the time when New Zealand's gas position moved to one of relative scarcity, all other factors being equal.

All of these factors combine to produce heighted uncertainty in the New Zealand gas sector. Indeed, the sector may be at a turning-point.

The significant drop in oil prices and outlook for exploration effort, coupled with the disappointing results from recent exploration efforts, point to a tightening of New Zealand's gas inventory.

Our analysis indicates that by 1 January 2017 the P50-reserves-to-production ratio will be close to 9 years – down from the 1 January 2014 figure of almost 14 years. If demand continues at present levels, and there are no significant new discoveries, the reserves-to-production ratio will fall further.

How things will develop will be a function of demand (particularly for petrochemicals and power generation) and supply (i.e. exploration effort and success – including the extent to which New Zealand's significant reported contingent resources for existing fields are developed[3]). The next sections in this summary discuss these issues in a little more depth. Readers can find further detail in the main body of this report.

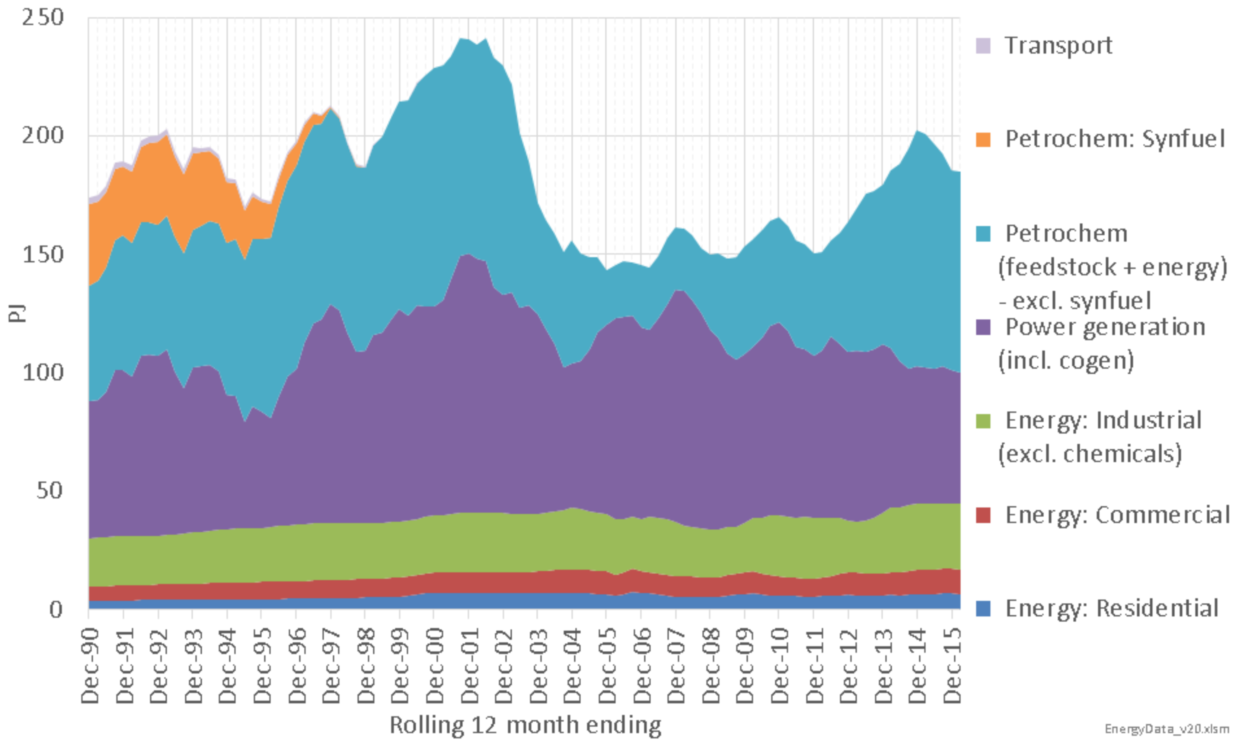
[2] This assumes that New Zealand continues to have a mechanism whereby any emissions-intensive trade exposed industries will not be put in a disadvantageous position relative to overseas companies who don't face a price of CO_2 – with the current industrial allocation mechanism being the current means of achieving this within the New Zealand Emissions Trading Scheme (NZ ETS). Were this situation to change, a high CO_2 price in New Zealand could result in emissions-intensive exporters exiting New Zealand (potentially resulting in an *increase* in global emissions if this loss of international market share is to more emissions-intensive overseas producers – a phenomena known as carbon leakage).

[3] Contingent resources are gas accumulations within known *existing* fields, but which are regarded as being sub-commercial based on current oil and gas prices. These contingent resources are not included within the estimate of P50 probable reserves.

Gas demand for petrochemical production

As illustrated in Figure 2 below, gas demand for methanol and (to a much lesser extent) urea fertiliser production has tended to rise or fall in response to changes in the domestic gas supply/demand outlook much more so than other sectors.

Figure 2: Historical sectoral gas demand



Source: Concept analysis of MBIE data

This is because this changing domestic gas supply/demand position affects the relative international competitiveness of the New Zealand petrochemical production plants far more than New Zealand's other gas consuming sectors. In effect, the presence of these petrochemical gas users provides a 'virtual' connection with international gas markets – especially those in North America which are the main competing source for methanol production.

Given its large size (currently accounting for over 45% of national demand), the petrochemical sector is both influenced by, and strongly influences New Zealand's gas market. If current levels of petrochemical demand were to continue, New Zealand's reserves-to-production ratio, *based on current P50 reserves*, is projected to fall to approximately 7 years by 1 January 2020, and 5 years by 1 January 2022.[4] Of course, this assumes that no other changes occur in the intervening period – in particular that no additional gas reserves are booked in that period, from existing or new sources.

How long petrochemical demand continues at current rates will be influenced by gas producers' incentives. If they recontract to maintain high levels of demand, the gas price for sale to Methanex is likely to reflect Methanex's opportunity cost of producing methanol at one of its overseas locations. This price may well be lower than the level which would prevail generally in a tighter New Zealand gas market.

However, gas producers may be willing to accept such a price, if the alternative is to keep the gas in the ground and postpone incremental sales for a significant period of time. In this respect, although the

[4] Calculated as estimated remaining 2P reserves, divided by production in the previous year (noting that this includes production to meet petrochemical gas demand). The reserves to production ratio in 2022 would be around 10 years if it excluded petrochemical demand – which is arguably the more relevant measure based on the discretionary nature of that demand.

reserves-to-production ratio as at January 2017 is projected to be 9 years based on current levels of demand, it would be around 18 years based on non-petrochemical sector demand (and 26 years if baseload gas-fired generation - the next most price-sensitive demand sector - is also excluded).

Thus, gas revenue 'now' may well be more valuable than sales a decade or more hence, even if such future gas sales are at materially higher prices. Plus, to the extent that keeping gas in the ground also postpones associated oil sales (albeit possibly at higher future prices) and extends the field life and associated operating costs, the incentive on producers to make discretionary gas sales earlier at a lower price may be even greater.

On the other hand, a tightening reserves position will put upward pressure on gas prices, and encourage producers to retain gas for higher value local users. The exact time when such a cross-over point will occur will depend on a number of factors including:

- international gas prices (which influence Methanex's ability and willingness-to-pay);
- oil prices (which comprise a significant additional part of a field's revenue stream);
- the dynamics of the New Zealand power generation market – being the other major 'discretionary' demand sector that would likely reduce gas demand in response to a tightening gas market; and
- the extent to which additional gas sources will be brought forward to the market.

This last point is particularly significant. Although there currently appears to be little prospect of *new* fields being commercialised within the next 5-7 years, New Zealand has a significant quantity of gas classified as 2C contingent resource. This is gas within known *existing* fields, but which is regarded as being sub-commercial at present. As at 1 January 2016, reported 2C resources were 1,700 PJ, in comparison to the reported 2P reserves of 2,060 PJ.

If the New Zealand gas market tightens and prices rise, this will improve the commercial case for developing 2C contingent resources, and likely lead to some 2C resource being converted to reserves. Further, higher gas prices would also likely bring forward the time when upstream producers resume significant exploration in New Zealand – noting that the prospectivity for additional gas in the Taranaki basin is still considered to be very positive.

Given these dynamics, it appears unlikely that the low reserves-to-production ratios projected for 2020 – 2022 based on *current* P50 reserves would eventuate in practice. A more likely scenario is that some contingent resources will be converted into reserves, if gas demand for petrochemical production is maintained at high levels.

At some later point, absent major new gas sources being identified, New Zealand's reserves could drop to a point where gas producers prefer to not to sell to Methanex. Evaluation of when such a position may emerge is subject to significant inherent uncertainty given the factors outlined above. However, if history is a guide to when such outcomes may occur, it may be instructive to note that Methanex rapidly reduced demand in the early 2000's once the P50-reserves-to-production ratio reached 6 years. Our projections indicate that, absent a major new gas discovery, New Zealand would reach that point in 2022 based on current levels of petrochemical demand and assuming some price response from the power generation sector.[5]

Therefore, it is potentially the case that we could continue to see relatively high petrochemical demand until approximately 2022, followed by a rapid scaling-back of methanol demand – potentially to close to zero – from that point on. Were such an outcome to occur, it is unlikely that the methanol plants would be permanently retired, but rather put into mothballs to enable a resumption of production if and when a significant new gas field were developed in the future. Such a strategy proved to be valuable for both Methanex and New Zealand's gas sector in the 2000's – i.e. Methanex is considered a key enabler for New Zealand's oil and gas sector.

---

[5] If the Tiwai smelter were to retire in 2018/19, the associated reduction in gas-fired power generation would push out the point where New Zealand's reserves-to-demand ratio reached this cross-over point by a couple of years.

It is unlikely that urea production – the other main petrochemical demand – would similarly shut-down at such a point. The fact that there is a large domestic market for urea means that Ballance (the urea manufacturer) has a significantly greater ability-to-pay than Methanex – which has little domestic demand for its methanol, and thus doesn't enjoy the large shipping cost advantage which NZ urea production does.

As regards the potential for expanded methanol production capacity at some point in the future, this appears relatively unlikely for Taranaki-based gas (see page 14 for discussion of non-Taranaki gas). In large part this is because of the relatively low likelihood of finding a field of a size large enough to support a new methanol production train for ≈15 years or more *in addition* to providing gas for the existing three trains over such a period.

That said, were a field of such a size (i.e. 3-5,000+ PJ) found in the Taranaki basin, new methanol trains would be one of the three main options for monetising such a discovery – with urea production or LNG being the other two options. The dynamics driving which option would be most likely to be developed are the same for the consideration of non-Taranaki gas as set out on page 14.

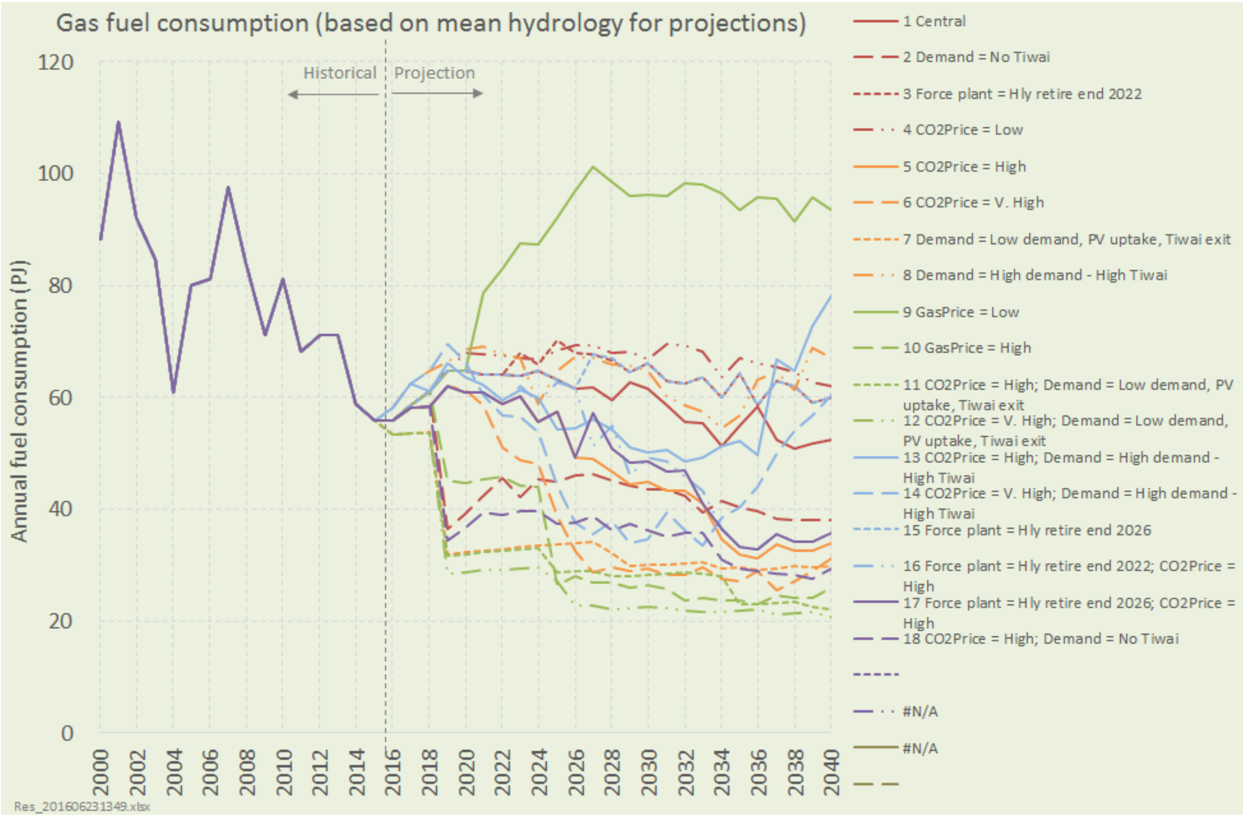
Gas demand for power generation

Gas demand for power generation has been trending downward as renewables account for a rising proportion of power supply.

Our Central projection (under mean hydrology) is for gas demand for power generation to rebound modestly in the near term, and then remain relatively flat before gradually declining in the very long term. This rebound occurs because near term growth in power demand is projected to be met mainly from spare capacity at existing gas-fired stations – noting that some of the recent development of renewables was likely an over-build in anticipation of higher electricity demand and CO_2 prices, neither of which eventuated – with further ongoing growth in power demand coming mainly from new renewable sources.

As is shown in Figure 3 below, a number of other projections were developed to examine potential outcomes due to situations of: relative gas plenty or scarcity (reflected in low and high gas prices), variations in CO_2 prices, and the impact of factors such as the potential retirement of the Tiwai aluminium smelter or the Huntly Rankine coal-fired station.

Figure 3:Projected gas demand for power generation under all scenarios



As can be seen, there are a wide range of possible outcomes, ranging from:

- An upper scenario in a plentiful gas world, where powergen gas demand rises to, and stabilises at, around 95 PJ/year (under mean hydrology) by mid-2020s as gas substitutes for coal and not as much renewables are built.[6]
- A lower scenario in a scarce gas world and/or high CO_2 price world, where gas demand contracts to, and stabilises around 25/PJ per year by mid 2020s.

Irrespective of the average level of gas demand for power generation, this sector will require significant gas swing – both on a seasonal basis to address increased winter electricity demand, and on a year-to-year basis to address significant variations in hydro output due to dry / wet years. While the seasonal swing can be largely met by the Ahuroa gas storage facility, it is likely that the year-to-year variation will require swinging of upstream production. At present, this year-to-year flex requirement is around 20-25 PJ – but could rise to 35-40 PJ if the Huntly power station were to retire.

This need for flexible power generation that can operate at lower capacity factors also tends to place a ceiling on the proportion of power that can be economically met from renewable sources – it is relatively expensive to build a wind farm which would only operate in winter, say, whereas the lower capital intensity of thermal power stations makes them more economic for such duties.

From the perspective of New Zealand's overall gas supply / demand balance, the power generation sector has historically played a similar role to that of petrochemicals, and is likely to continue to do so in the future.

Our modelling indicates that there could be a significant degree of long-term demand variation from the power generation sector in response to higher or lower gas prices. However, unlike the petrochemical

[6] It is possible that this scenario may be less likely as it would not be consistent with the government's stated target of achieving 90% renewable generation by 2025. As such, it would only be likely to eventuate in a future of plentiful gas *and* where government didn't impose other policy mechanisms (e.g. higher CO_2 prices) to achieve particular environmental outcomes.

sector which can very rapidly reduce / increase demand in response to a changing supply position, the change in demand from the power generation sector would be likely to be much slower, relying as it does on changing investment in renewable generation.

Further, there are likely to be upper and lower limits to demand from the power generation sector:

- It appears unlikely that gas prices will fall to a level which would justify building *new* baseload combined-cycle gas-fired turbines (CCGTs), particularly in an environment where CO_2 prices rise and the cost of renewables is likely to continue to fall.[7] This will place an upper-limit on gas demand from the power generation sector: being the amount of demand to meet close-to-baseload duties for the existing CCGTs, plus low-to-medium capacity factor duties from existing and new OCGTs. Further, the building of new CCGTs would be inconsistent with the government's current target of 90% renewable generation by 2025.
- It becomes progressively more expensive to build renewables to displace existing thermals from ever lower-capacity-factor duties. Thus, even at very high gas prices, it will still be economic to have some OCGT plant to provide low-capacity factor duties.

This dynamic of differing requirements for different power-generation duties (baseload, dry/wet-year balancing, seasonal peaking, and daily peaking) also means there is no single price that gas-fired power generation would be prepared to pay. Thus, peaking gas-fired generation can afford to pay a lot more per GJ than higher-capacity factor gas-fired generation which is much more directly in competition with new renewables.

Lastly, the modelling indicates the major dislocation that would occur if the Tiwai aluminium smelter were to retire – which contractually it is able to do from 2018. This would lead to an immediate reduction in gas demand of approximately 25 PJ per year (≈ 13% of national demand) and the likely retirement of at least one CCGT and a Rankine unit, and a longer-term reduction of approximately 15 PJ per year.[8]

Gas demand for direct use by industrial, commercial and residential users

Gas for 'direct use' refers to the ~250,000 industrial, commercial and residential gas users, who use gas as an energy source for heating purposes (space and water heating, and industrial process heat). This group is the most stable segment of demand with future variations in demand likely to predominantly be driven by variations in population and economic growth, rather than in response to New Zealand's changing gas supply / demand position.

This reflects the fact that, for most direct-use consumers, wholesale gas prices will generally need to rise very significantly in order for gas to become more expensive than alternatives. This is because most alternative fuels suffer from some combination of:

- high appliance capital costs that would be incurred from a fuel switch;
- high wholesale fuel costs (in the case of biomass, diesel, and LPG); and
- high transport costs.

Further, unlike for the petrochemical sector, energy costs generally comprise a relatively small proportion of consumers' total inputs. This means that, apart from some industrial consumers in sectors suffering an economic downturn, a rise in wholesale gas prices would be unlikely to cause most consumers to exit New Zealand completely.

That said, in the long-term a tightening gas supply position and associated rise in prices would be expected to depress demand relative to what it would otherwise be, and vice versa for a position of

[7] The fall in the cost of renewables is due both to ongoing technology improvement (particularly for wind), coupled with low interest rates and steel prices.

[8] The long-term reduction is less than the immediate reduction due to the likely altered build patterns of other generation (particularly renewables) that will re-balance New Zealand's generation portfolio.

relative surplus. However, the rate of change would be expected to be very slow, with fuel-switching decisions by consumers predominantly coinciding with times where they need to make an appliance capital decision – i.e. for new consumers, or where an existing appliance has reached the end of its useful life. Our Central case sees a gradual increase in the direct use demand, driven mainly by population and economic growth. The Low case projects a gradual decline in direct use gas demand, whereas the High case projects a gradual increase.

Gas supply

Gas has been supplied continuously from the Taranaki region since the early 1970s – and is currently sourced from a range of onshore and offshore fields. Although exploration has occurred in other regions and has identified hydrocarbons, Taranaki is likely to remain the main supply source for existing users for the foreseeable future.

As mentioned above, New Zealand's reserve-to-production ratio is likely to decline from the recent levels of 12 years' cover to approximately 5 years' of cover by 2022 if total demand continues at current levels, and there are no additional reserves are booked.

In physical terms, there are multiple sources available to replenish reserves and/or meet future gas demand - the supply outlook is primarily an economic rather than physical issue. In this respect, there is a significant amount of gas which is identified in known accumulations, but is classed as contingent resources because it is sub-commercial at the current combination of gas and oil prices.[9] Likewise, there are other prospects which are unlikely to be explored until gas and oil prices rise to sufficient levels.

Oil prices will have an important influence on new supply, because New Zealand's gas is typically produced from gas-condensate fields. Lower oil prices make New Zealand exploration and development activity relatively more dependent on revenues from gas sales (requiring higher average gas prices), and vice versa. This dynamic means there could be an inverse correlation between world oil prices and New Zealand gas prices.

Looking ahead, most international forecasters expect some recovery in oil prices – which will be supportive of New Zealand upstream activity and the gas supply outlook. That said, there is significant uncertainty about the trajectory of future oil prices, and most commentators consider it unlikely that oil prices will return to the US$100/bbl+ prices seen at the start of this decade.

Summary / National gas demand scenarios

In summary, after a period of high oil prices and associated exploration effort which gave rise to a situation of relative surplus, New Zealand looks to be heading towards a tightening gas supply position.

In the medium-to-long-term this is likely to result in a contraction of demand from the petrochemical and power generation sectors, absent a resumption of major exploration and development effort.

This contraction from these relatively more price-sensitive sectors will play an important role in allocating gas towards higher value uses. That said, we may see a continuation of relatively high petrochemical demand for the next 5 or so years.

As well as ensuring gas is allocated to the highest value uses, the higher gas prices that are likely to eventuate from a tightening supply position will play an important role in stimulating renewed upstream exploration and development activity – including developing the significant quantity of gas currently classified as contingent resource.

[9] This is similar to the Kupe field which was first discovered in the mid 1980's but wasn't developed at that time because of New Zealand's surplus gas position due to the Maui field. It was eventually developed during the late 2000's (coming to market in 2010) after New Zealand's gas position became much tighter and world oil prices rose significantly.

With subdued oil prices, it is possible that New Zealand gas prices may rise more than they would otherwise have done.

At the very least, renewed exploration and development effort is likely to produce sufficient gas to meet the foreseeable demand of New Zealand's highest-value gas users: direct-use industrial, commercial and residential users, plus gas-fired peaking generation.

There is also a reasonable possibility that renewed exploration and development effort could result in the development of a significant new gas field. Were this to be the case, there is a high likelihood that a significant proportion of such gas would be used for petrochemical production – particularly methanol. In this respect, New Zealand's petrochemical sector plays an important role as a facilitator of the upstream petroleum sector: upstream producers can have confidence that if they make a significant gas discovery, they will be able to monetise it at similar prices that they would be able to achieve in other places around the world.

Based on the above, Concept has developed some overall demand projections, based on three broad market scenarios:

- Plentiful – representing a future where gas exploration and development brings forward significant new supply from existing and/or new fields. This is more likely in a scenario of sustained high future oil prices, which generally encourage active upstream exploration and development.
- Scarce – representing a future where no major new supply sources are developed, and future development is largely around firming up incremental gas supply from existing fields. This is more likely in a scenario of sustained low future oil prices. Prices in this scenario are likely to be capped in the long-term at the level which it starts to become economic to import LNG – although this outcome may be relatively unlikely as it is probably more economic to develop New Zealand's reported contingent resources at prices below this LNG import parity level.
- Central – representing a situation between these two extremes.

Medium-to-long-term demand from the petrochemical sector is considered to be largely a function of New Zealand's supply position. It appears likely that gas demand for methanol production will continue at relatively high levels over the next five years or so, but significantly scale back if there is no major additions to gas supply identified in that period.

Our central projection for petrochemical demand is simply an average of the plentiful and scarce scenarios. However, in reality, methanol demand (which accounts for the vast majority of petrochemical demand) may be more binary, being at either high or low levels, depending on the extent of forward reserves cover.

The power generation gas demand scenarios for the Plentiful and Scarce scenarios are represented by the Gas Price = Low, and Gas Price = High, scenarios, respectively, as shown in Figure 3 above.

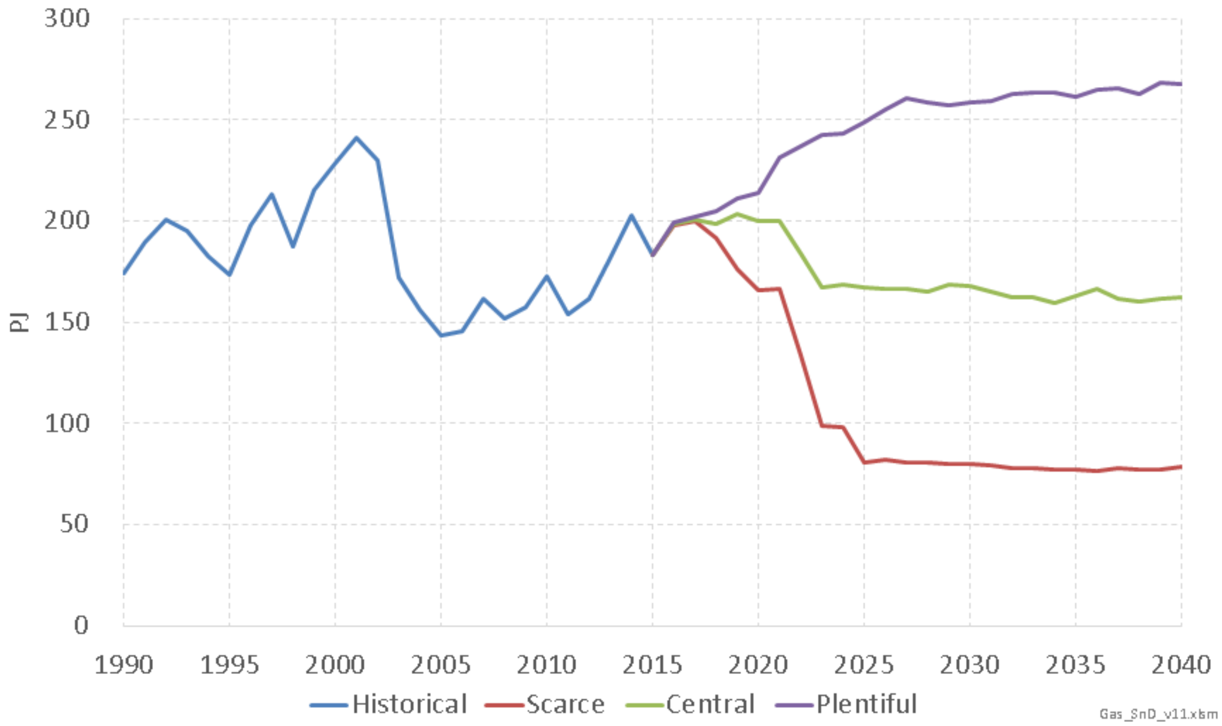
In contrast, demand for direct-use for industrial, commercial and residential is likely to exhibit relatively little volatility, with only gradual changes in response to New Zealand's changing supply position, and with demand changes largely being driven by population and economic activity.

Figure 4 shows the demand projections for 2016-2040 at the aggregate level. Key observations are:

- The projections show a wide range of possible demand levels in future years
- The Plentiful, Central and Scarce scenarios should not be interpreted as equally 'likely' – rather the Plentiful and Scarce cases present possible (but unlikely) 'bookends' for demand – actual outcomes are more likely to be around the Central scenario case – at least for the next few years
- The differences between the scenarios are mainly driven by variations in the 'discretionary' gas users in the petrochemical and power generation sectors – direct use of gas is relatively stable in all scenarios

- For the next few years, gas demand is projected to remain around current levels - further information on drivers may crystallise in the next 12 months – particularly in relation to methanol production plans for plants which appear to have scheduled maintenance turnarounds in ~2017/2018.

Figure 4: National gas demand projections



Source: Concept analysis

Non-Taranaki gas

The above discussion has focussed entirely on New Zealand's *existing* gas market – with production located entirely from fields in the Taranaki basin, and transmission networks radiating out from Taranaki to the main North Island load centres.

However, New Zealand has a number of other prospective sedimentary basins – including several in the South Island (particularly the Canterbury, and Great South basins) and other locations in the North Island (including Eastland, and the Far North).

If gas is discovered and/or developed in these other locations, it is likely to have minimal impact on New Zealand's existing Taranaki-based gas market. This is because the cost of the gas transmission pipelines necessary to 'join' these new markets to the existing market is likely to be prohibitive. Rather, it would likely be more economic to develop new sources of gas demand close to these new locations.

The main options for new large scale demand are LNG, methanol or urea for sale overseas.[10] Which option would be most economic would depend on the extent to which each of the three commodities was in a situation of relative global production over- or under-capacity, and the extent of any regional dynamics relating to demand and competing marginal international sources of supply (noting that shipping cost differentials can materially impact on the relative economics of producing these commodities). It is potentially the case that an extremely large find would be more likely to be developed for LNG production whereas a smaller find may be better suited to petrochemical production.

[10] A find in the South Island could potentially also be used to displace existing coal-fired process heat in the dairy processing sector.

However, the economics of these markets mean that the gas netbacks for such sales are likely to be approximately half the level which could be achieved in the Taranaki-based market with its existing production infrastructure and existing methanol production plant.

Relationship with earlier reports

This 2016 Gas Supply and Demand report is the third to be commissioned by Gas Industry Company, following previous reports in 2012 and 2014.

While all three reports have a similar general purpose – each has explored certain issues in more detail – reflecting particular areas of importance at the time:

- For the 2012 report it was analysis of peak capacity issues, and implications for network investment and capacity allocation on the northern gas transmission system.
- For the 2014 report it was analysis of the power generation sector, and developing more detailed projections of gas outcomes on a scenario basis.

For this 2016 report issues that have been explored in more detail include:

- The implications of a lower oil price (= lower hydrocarbon exploration) future on New Zealand's long-term gas supply position.
- The implications of major changes in the power generation sector, specifically:
  - Potential exit of the Tiwai aluminium smelter (with associated likely retirement of gas-fired plant such as the Taranaki Combined Cycle plant)
  - Potential retirement of the Huntly Rankine units, and the associated implications on demand for gas swing, including to manage dry year risk.
- The outcomes if future CO_2 prices are significantly higher than have been experienced historically.
- Development of demand projections for individual distribution networks, taking into account regional differences in: demand composition (residential, commercial, industrial), and demand drivers (particularly population growth).[11]

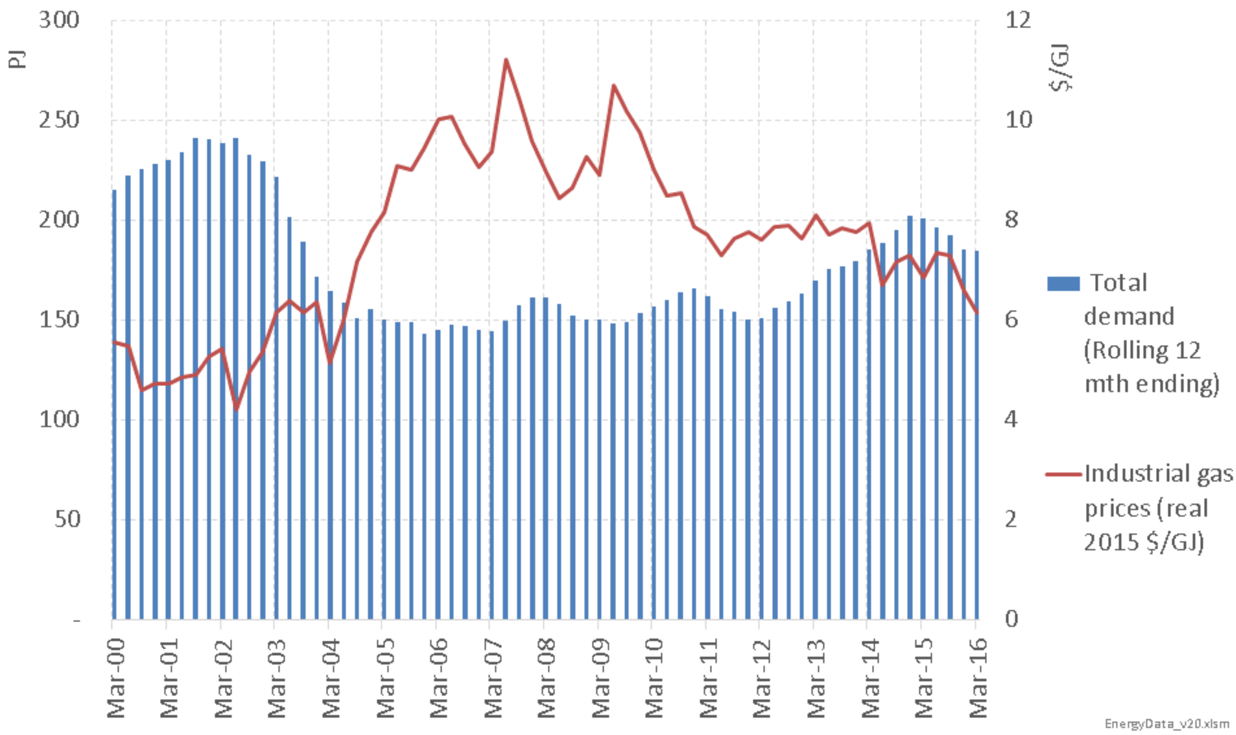
[11] The development of these distribution-network-specific demand projections was following a request by the Commerce Commission to Gas Industry Company. Specifically, for the projections developed for this Supply / Demand study to be of a form which could potentially be used as inputs to the constant price revenue growth forecasting modelling for setting gas distribution network prices for the next regulatory control period.

1 Purpose and structure of report

1.1 Purpose

Figure 5 shows that New Zealand's gas demand and wholesale prices have exhibited considerable variation over the past 16 years.

Figure 5: Historical gas demand and prices



Source: Concept analysis using MBIE data

This study explores the underlying drivers of these historical outcomes, and how future changes to such drivers (and potential new drivers) may influence outcomes going forward.

We hope this information will help interested stakeholders to better understand the medium to longer term outlook for the New Zealand natural gas[12] sector, and assist them with future gas-related decisions.

1.2 Structure of this report

The structure of this report is as follows:

- Section 2 analyses the factors driving upstream gas supply, and sets out possible indicative scenarios for market conditions and wholesale gas prices
- Section 4 analyses gas demand for petrochemical manufacturing, and develops future demand projections for this sector
- Section 5 analyses gas demand for power generation, and develops future demand projections for this sector
- Section 6 analyses gas demand for direct use, and develops future demand projections for this sector
- Section 7 draws together the key findings from the previous three chapters, and sets out projections for aggregate gas demand under a range of scenarios.

[12] Henceforth, references to 'gas' means natural gas, unless otherwise stated.

1.3 Relationship with earlier reports

This 2016 Gas Supply and Demand report is the third to be commissioned by Gas Industry Company, following previous reports in 2012 and 2014.

While all three reports have a similar general purpose – each has explored certain issues in more detail – reflecting particular areas of importance at the time:

- For the 2012 report it was analysis of peak capacity issues, and implications for network investment and capacity allocation on the northern gas transmission system.
- For the 2014 report it was analysis of the power generation sector, and developing more detailed projections of gas outcomes on a scenario basis.

For this 2016 report some of the issues that have been explored in more detail are:

- The implications of a low oil price (= low hydrocarbon exploration) future on New Zealand's long-term reserves position.
- The implications of major changes in the power generation sector, specifically:
  - Potential exit of the Tiwai aluminium smelter (with associated likely retirement of gas-fired plant such as the TCC combined-cycle gas turbine)
  - Potential retirement of the Huntly Rankine units, and the associated implications for gas upstream deliverability, including to manage dry year risk.
- The outcomes if future CO_2 prices are significantly higher than have been experienced historically.

In addition, for this report, demand projections for users connected to the main gas distribution networks have been developed at a greater level of granularity. This is to facilitate their potential use as inputs in the Commerce Commission's forthcoming price-quality determinations for regulated gas pipeline businesses.

2 Market Scenarios

Chapter summary

The uncertain and lumpy nature of gas discoveries means that New Zealand faces a range of possible futures. Three market scenarios have been developed to broadly reflect these possible futures:

- 1) ***Scarce*** – reflecting a market where new gas resources are unable to be brought to market at a rate to match usage, and New Zealand's gas inventory shortens significantly.
- 2) ***Central*** – reflecting a market that is in broad equilibrium, where further gas resources are brought to market at a rate that more or less matches New Zealand's demand over time.
- 3) ***Plentiful*** – reflecting a scenario that would arise due to a sustained 'excess' of gas, and would be reflected in high reserves to production ratios.

New Zealand's reserves to production (RTP) [13] ratio has been ~10-12 for the last eight years, reflecting a market that has been in broad equilibrium. Under these conditions, wholesale gas prices[14] are expected to generally be in the $5-7/GJ range.

The available public data on wholesale gas prices suggests that they have been around $5-6/GJ over the last 12-24 months. This data falls within this range noted above (albeit the lower part of the range), supporting the view that the market is currently in broad equilibrium.

We expect the RTP ratio to reduce over the next 1-2 years (and possibly longer) for reasons further discussed in section 3. While a declining RTP ratio is expected to put some upward pressure on gas prices all other factors being equal, the effect is unlikely to produce a sharp movement in the near term. In part, this is because current pressures represent a reversal of those acting over recent years, which have been pushing more towards relative surplus than scarcity.

Furthermore, a large proportion of current gas use is accounted for by methanol production. This segment of demand is likely to scale back its usage if there are *sustained* reductions in RTP ratio and associated upward pressure on prices.

On the other hand, it appears unlikely that the RTP ratio will increase substantially in the near term, given the prevailing weak oil prices (and thus low exploration) and inherent lags before new upstream resources can be brought into production.

2.1 Purpose

This section describes a range of possible scenarios for the overall state of the gas market. These scenarios are 'scene-setters', and are used later in this report to inform the development of some sector specific projections for gas demand.

The scenarios are not forecasts per se, but rather provide indications of possible futures under the specific scenario assumptions. They also assume that all other factors outside the scenario variables remain the same (e.g. demand by reticulated users is relatively stable).

2.2 Possible market states

While there is a continuum of possible gas supply states, it is useful to consider three key market scenarios: Scarce, Central, and Plentiful. These states are useful because they define the possible 'book ends', and a 'middle' zone.

---

[13] As discussed later, the RTP provides a measure of the identified level of gas inventory for New Zealand.

[14] These price estimates are for an annual contract with relatively little swing, for delivery at the Frankley Rd hub in Taranaki. They do not include network or retail costs which are a very large component of the overall cost of supply for residential and commercial consumers.

Table 1 describes each market scenario and the demand-side or supply-side factors that could cause it to arise. The table also describes the key drivers that would be expected to influence prices in each scenario.

It is important to note that the indicative prices for the Scarce and Plentiful scenarios reflect expected levels if the relevant market conditions were to persist over a sustained period.

However, as discussed later in this report, such outcomes appear relatively unlikely because there are natural balancing forces that are likely to move the market toward the Central conditions over time. For this reason, the price levels for these scenarios effectively represent the likely upper and lower bounds respectively, with prices being unlikely to remain at such levels on a sustained basis over the long-term.

Table 1: Supply scenarios

Market scenario	Indicative price (real 2016 $/GJ)	Description
Scarce = High prices	~$10-$12	This scenario reflects a market where new gas resources are unable to be brought to market at a rate to match usage, and New Zealand's gas inventory shortens significantly. This would be more likely in a situation of sustained low world oil prices, and consequent low levels of exploration. Gas demand for methanol production will likely progressively decline which will help balance demand with supply. If insufficient gas is still not found methanol production will likely completely cease, and other gas consuming uses will start to reduce consumption – particularly remaining gas use for baseload power generation, urea production, and some industrial process heat. The opportunity cost of these other uses will likely set the price of gas as a particular end-use becomes the marginal source of gas demand. Alternatively, prices might be set by the cost of imported gas in the form of liquefied natural gas (LNG)[15]. Methanol production will have completely ceased along with urea production and some industrial process heat. Power generation will decline, however, there will still be a need for some power generation to provide dry year swing. In recent years the minimum size of a market for LNG import has come down, recent estimates put the minimum market size at around 60PJ per year. However, with Australia's LNG export market being located within a short shipping distance to New Zealand this may reduce the minimum size even more. However, given the relatively large size of contingent gas resources in New Zealand, which would be more likely to be economic to develop than importing gas as LNG, this scenario of importing LNG may be relatively less likely. Another possible driver for this scenario is discovery of a gas field that is large enough to develop for LNG *exports*. In this case, the price of gas would rise to the net-backs achievable for sales of LNG

[15] LNG is transported between countries via ship.

		on the world market – something that the Australian market is now experiencing following the development of its LNG export facilities. In this case, the market becomes 'tight' because a new category of gas demand emerges. However, as discussed in Appendix A this scenario appears relatively unlikely, given that LNG-scale finds in New Zealand are unlikely to be found close to the existing Taranaki-based gas market, and thus such developments will effectively be isolated from the rest of the New Zealand gas market.
Central	~$5-$7	This scenario reflects a market that is in broad equilibrium, where further gas resources are brought to market at a rate that more or less matches New Zealand's demand over time. Gas demand for petrochemical production is likely to be the marginal buyer, provided a sizeable proportion of the existing plant capacity in Taranaki is available for operation. The price range is strongly influenced by the economics of producing methanol in New Zealand versus other international locations as discussed in section 4.2.1. Within this range, prices are likely to float reflecting shorter-term factors such as prevailing methanol prices, hydro inflows, etc.
Plentiful = Low prices	~$2.5-$4	This scenario would arise due to a sustained 'excess' of gas, and would be reflected in high reserves to production ratios. This would be more likely in a situation of sustained high world oil prices, and consequent high levels of exploration. The likely trigger would be a sizeable find of gas that is associated with liquids - creating strong incentives for the producer to sell gas to facilitate oil production. Such finds would need to be large and close to the existing North Island gas transmission network. In the limit, the floor for this market scenario is likely to be set by the economics of deferring gas and liquids production and/or the price that *new* gas consuming petrochemical facilities would be willing to pay (e.g. a new fertiliser or methanol production plant), as discussed in section 4.2.1.

The next sections briefly discuss the relative likelihood of different scenarios, in both the near and longer term.

2.3 Medium-term market outlook (< 5 years)

A statistic that provides a measure of New Zealand's 'inventory' of discovered gas is the reserves to production (RTP) ratio. This indicates the expected number of years to deplete existing reserves, at the prevailing rate of gas production. Aside from producing from existing reserves, it assumes that all other factors remain unchanged.

New Zealand's RTP ratio has been ~10-12 for the last eight years, reflecting a market that has been in broad equilibrium (as shown in Figure 17). Under these conditions, wholesale gas prices[16] are expected to generally be in the $5-7/GJ range.

[16] These price estimates are for an annual contract with relatively little swing, for delivery at the Frankley Rd hub in Taranaki.

The available public data on wholesale gas prices suggests that they have been around $5-6/GJ over the last 12-24 months (see Appendix B for more information). This data falls within this range noted above (albeit the lower part of the range), supporting the view that the market is currently in broad equilibrium.

However, there has been little exploration success over the last couple of years, and with current low oil prices there is little exploration effort which is targeting material new gas sources.

Accordingly, if the current levels of demand were to continue then, New Zealand's reserves-to-production ratio, *based on current P50 reserves*, is projected to fall to approximately 7 years by 1 January 2020, and 5 years by 1 January 2022. This would be expected to put upward pressure on gas prices.

Apart from success in commercialising new supply sources (including the significant quantity of contingent resources reported for existing fields), the single largest factor driving New Zealand's future reserves position will be the level of demand from the petrochemical sector which currently accounts for over 45% of national demand. In this respect it is thought that all three of Methanex's methanol production trains are coming up for major plant turn-arounds in 2017/18, when decisions are likely to be required on their intended level of operation for the subsequent 4-5 years.[17]

Section 4.2 sets out a discussion about the Methanex re-contracting dynamics and the relative incentives on producers and Methanex. It concludes that we could see Methanex re-contract at similar levels for the period to 2017/18 to 2012/22 due to the incentives on producers to make such discretionary gas sales 'now' rather than in 10-15 years' time. However, beyond that time, absent significant new gas supply sources being identified, the decline in the reserves-to-production inventory position that would have occurred during this period would likely cause methanol production to significantly scale back – potentially to zero – with such plant put into mothballs (to be held against the potential discovery of another significant gas find at some point in the future).

In summary, while a declining reserves-to-production ratio is expected to put some upward pressure on gas prices all other factors being equal, the effect is unlikely to produce a sharp movement in price in the near term. Thus, the most likely outcome over the next couple of years appears to be the Central scenario, with a continuation of gas prices at around existing levels. In part, this is because current pressures represent a reversal of those acting over recent years, which have been pushing more towards relative surplus than scarcity. However, towards the back end of this 5-year period, absent any material exploration success, we would expect there to be pressures to move prices to the upper end of this Central scenario range, while noting that any material change in expectations of the longer term outlook could feed back into near term prices.

2.3.1 Longer-term market outlook (5+ years)

As we look further into the future, there is more uncertainty about potential outcomes because a greater range of factors can come into play as the time horizon extends.

One of the most significant uncertainties is the level of oil prices. As discussed in section 3.5.1, oil prices have an important influence on gas market dynamics in New Zealand. Assuming a recovery in oil prices within the next 5 years (albeit to levels below the peaks of 2012), the Central scenario appears to be the most likely outcome over time.

The fundamental reason for this view is that the balancing mechanisms that have influenced the New Zealand gas market over the last decade would be expected to continue to operate. More specifically, if the gas supply position were to tighten materially, discretionary demand (especially methanol

[17] Methanol production requires replenishment of the catalyst at periodic intervals – at which time other major maintenance is also undertaken. Based on observed historical patterns of such turn-arounds for the Taranaki plant, these tend to occur at 4-5 year intervals. Given the capital cost associated with such turn-arounds, it is understood that methanol producers seek to contract forward for a significant proportion of the subsequent 4-5 years' worth of required gas purchases.

production) would be likely to decline, reducing the rate of reserves depletion. Conversely, if gas supply conditions were to be plentiful, such gas users would be likely to operate at, or close to, full available capacity. And if there was sufficient supply, it is likely that new sources of gas demand would be stimulated.

However, if oil prices were to be sustained at relatively low levels over the medium term, this could affect these dynamics. This scenario would shift the economics of New Zealand upstream activity towards greater reliance on gas sales for revenues. Ultimately, if such a shift were sufficiently large, it would raise gas prices to a point where large discretionary gas users, such as methanol production, became uneconomic. In effect, this dynamic could produce conditions that are similar to the Tight Supply scenario (albeit with gas prices that are likely to be between the broad equilibrium and tight supply scenarios).

Conversely, if oil prices were to rise to high levels (circa 2012 or higher) on a sustained basis, that would be likely to have the opposite effect. It would stimulate upstream activity more generally, and make it more likely that gas market conditions come to reflect the Plentiful Supply scenario, at least on a periodic basis unless new investment occurs in gas using plant. This again highlights the tendency for an inverse relationship to exist between oil prices and New Zealand gas prices.

For the reasons discussed in section 3.5.1, there is considerable uncertainty about future oil prices. However, most major forecasters are expecting some recovery in oil prices over time. Assuming that occurs, then the most likely scenario for the gas market would be the Central case over time, but likely moving between periods of relative plenty and scarcity on a periodic basis.

3 Gas supply

Chapter summary

For most of the last decade, New Zealand's gas sector has enjoyed a strong tailwind from high oil prices. That tailwind has supported high levels of upstream activity - benefiting New Zealand's gas sector because oil and gas have typically been found together in this country.

Another important feature of the New Zealand gas sector is that it is not physically connected to other gas markets. This is relatively unusual for a western economy, with Iceland being the only other OECD country without a physical ability to transport gas to / from other gas markets.

As a result, any gas produced in New Zealand must be consumed within New Zealand. This contrasts with oil production in New Zealand given that it is relatively straightforward to export oil to international markets

The fact that any gas produced in New Zealand must be consumed domestically has implications for the economics of exploration and production. In particular, an upstream producer must have confidence that it can commercialise any gas that is found through selling to New Zealand-based gas consumers.

The two sectors which have fulfilled this role in New Zealand are the power generation and petrochemical sectors – particularly Methanex's two methanol production plants which have significantly varied their consumption to match the changing supply / demand position over the last 20+ years. The presence of this large source of flexible demand (Methanex gas demand is estimated to be ≈ 45% of projected total NZ demand for 2015) has been a key enabler of upstream exploration and production.

In physical terms, there are many potential sources of supply to meet gas demand in New Zealand – these include:

- Existing or new fields in the Taranaki basin
- New fields in one or the more of the 17 other petroleum basins across New Zealand
- Unconventional gas sources
- Imported gas

Given the wide range of potential physical supply sources, the outlook for gas supply is primarily an economic issue. This in turn is influenced by a number of drivers including:

- The price of crude oil
- The demand for gas from users within New Zealand, most importantly petrochemical production and power generation
- Carbon prices.

Since 2015, oil prices have been much lower. New Zealand upstream participants have reacted by reducing or delaying discretionary spending. For example, exploration expenditure in 2015 was only 4% of the amount spent in 2014.

Exploration and development activity is expected to remain at reduced levels until there is a strengthening in the outlook for oil prices. This reduced activity in turn is expected to contribute to a tightening of gas supply in New Zealand, all other factors being equal.

The key question is what *expectation* producers will have for future oil and gas prices, since that affects decisions by upstream participants about how much effort to apply to exploration and development. Most major international forecasters expect some recovery in oil prices – albeit to levels below the US$100/bbl mark. For example, a recovery to US$60/bbl would be a significant lift compared to prices recorded in H1 of 2016.

However, no one knows for certain whether recent oil price weakness is an aberration, or a sign of the future. As a result, New Zealand is currently at a cross-roads as to where gas exploration activity will head. If the oil prices remain persistently low, the gas market is likely to tighten and place upward pressure on gas prices. On the other hand, if oil prices recover from current subdued levels (albeit not necessarily to historical high levels), that would support some recovery in exploration activity in New Zealand – making it more likely that new gas discoveries are sufficient to sustain domestic gas demand from reticulated and power generation, and maintain some petrochemical production.

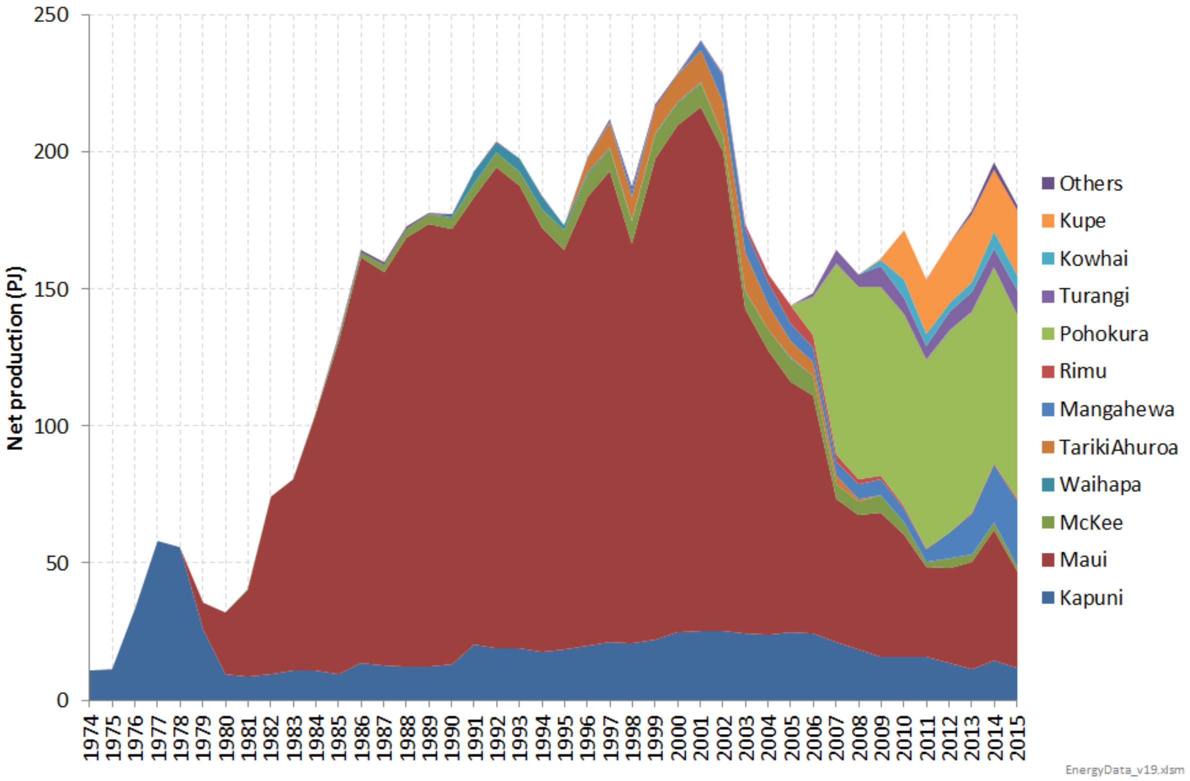
3.1 Purpose

This section provides an overview of gas supply and production in New Zealand.

3.2 Historical development of gas supply

Gas production started in New Zealand in the early 1970s at the onshore Kapuni field. Supply ramped up through the 1980s when production commenced from the much larger offshore Maui field. As Figure 6 shows, production from the Maui field dominated the New Zealand gas sector between 1980 and 2005. The presence of the large Maui field underpinned the development of gas-using industries, such as petrochemical production and thermal power generation.

Figure 6: Historical gas production in New Zealand



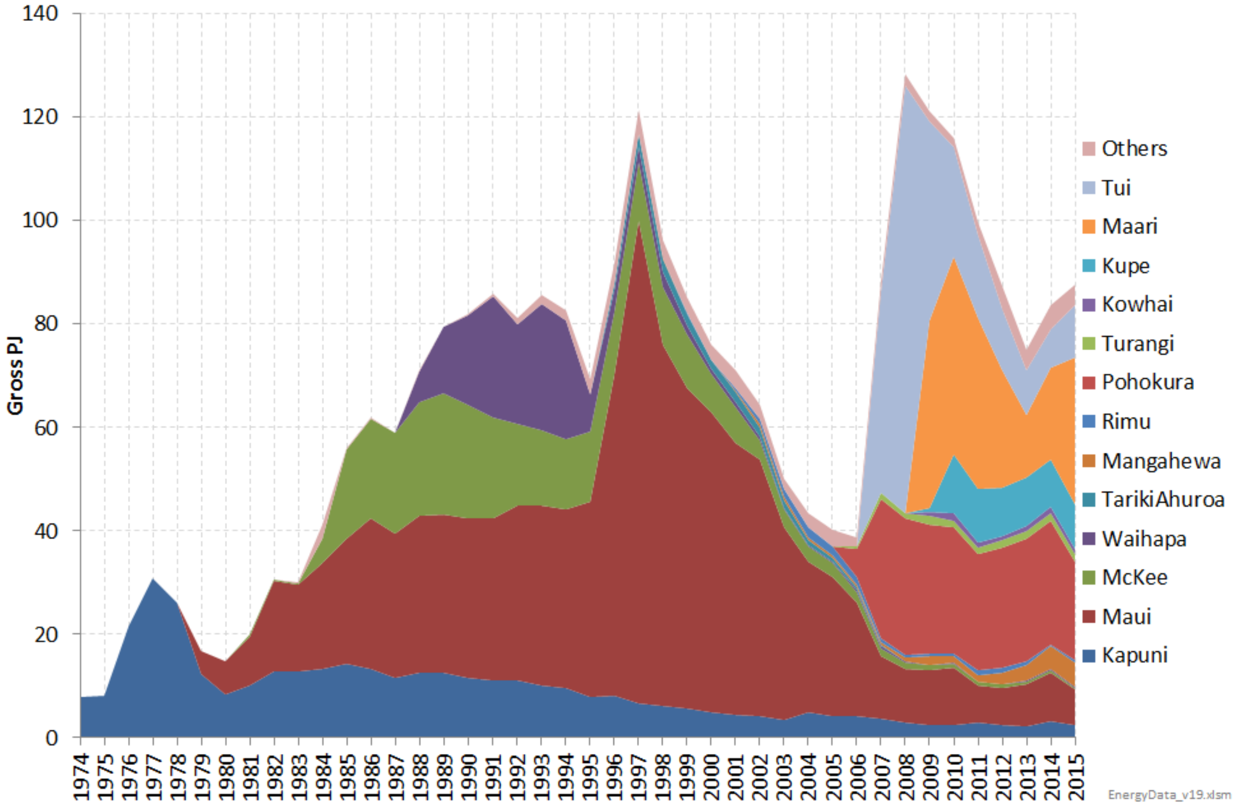
Source: Concept analysis using MBIE data.

Although alternatives to the Maui field had been identified as potential new sources of gas in the 1980s, there was insufficient incentive to develop these because gas demand could be met from Maui. That position changed in the early 2000s, when there was a sharp downward reassessment of the remaining reserves in Maui.

This led to a tightening of the gas market and higher gas prices. This in turn spurred the development of new fields, notably Pohokura and Kupe. The increase in gas (and liquids) prices also increased efforts to extend production from within existing fields, including Maui.

That is not to say there was no hydrocarbons exploration and development in New Zealand during the 1980's and 1990's. As Figure 7 below shows, the McKee and Waihapa fields were developed in the 1980s. However, these are / were predominantly oil producing fields, with relatively little gas being produced. More recently, the offshore Maari and Tui fields have been developed, with these fields producing only oil.

Figure 7: Historical oil production in New Zealand



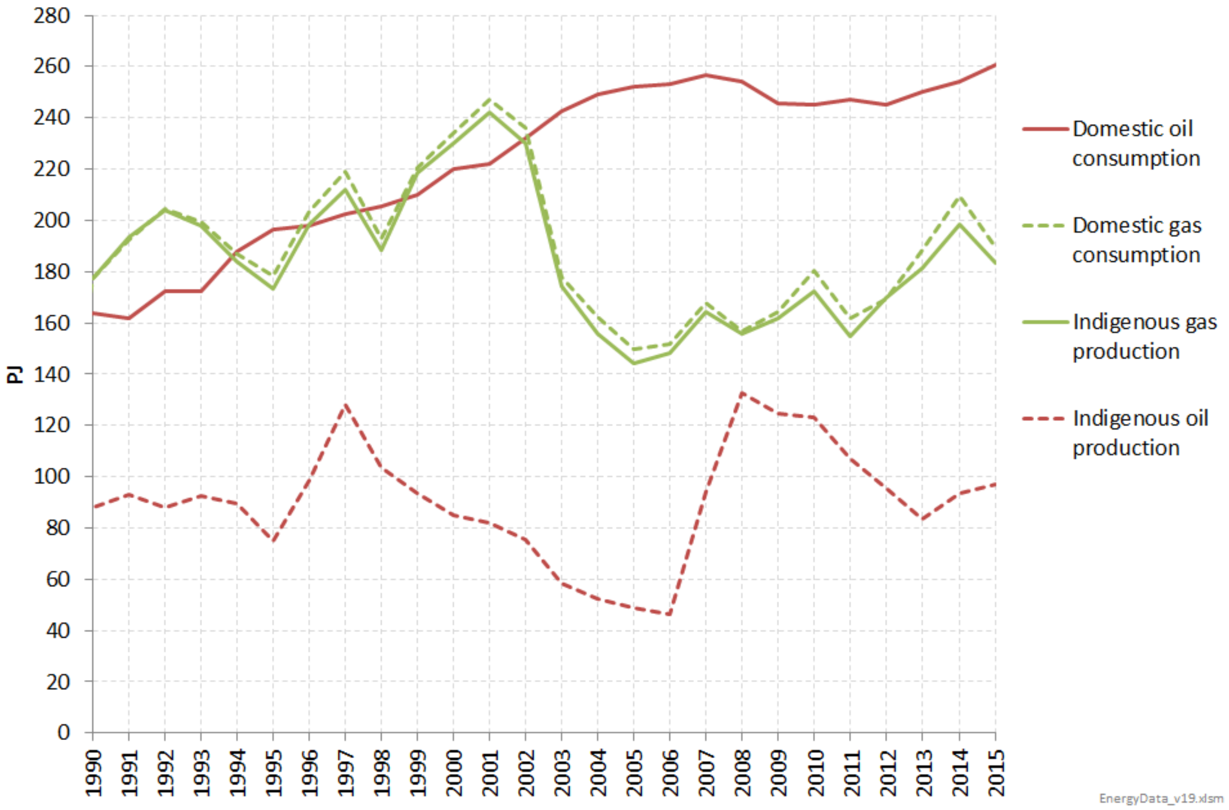
Source: Concept analysis using MBIE data

To understand this apparent relative lack of gas exploration effort in the decades following Maui's development, and the difference with oil exploration and production, it is necessary to understand an important feature of the New Zealand gas sector – namely that it is not physically connected to other gas markets.

This is relatively unusual for a western economy, with Iceland being the only other OECD country without a physical ability to transport gas to / from other gas markets. All other OECD economies are connected to other gas markets: either through pipelines, or through having LNG import or export capabilities.

The implication of this is that any gas that is produced in New Zealand must be consumed within New Zealand. This also contrasts with oil production in New Zealand given that it is relatively straightforward to export oil to international markets via ship. This difference between New Zealand's gas and oil sectors is illustrated in Figure 8 below.

Figure 8: Historical gas and oil production and consumption[18]



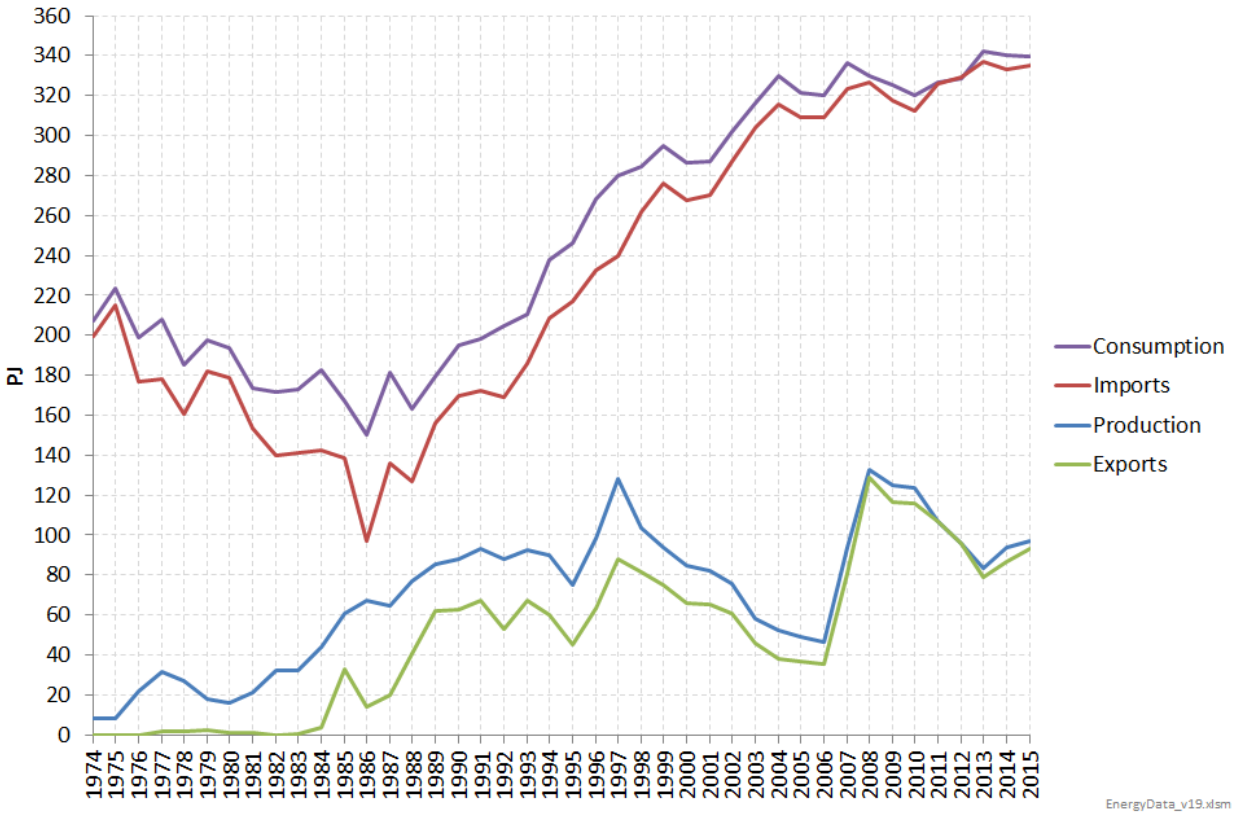
Source: Concept analysis using MBIE data

The production and consumption of gas in New Zealand is almost exactly equal[19], whereas there is a huge difference between indigenous oil production and domestic oil consumption.

Indeed, as Figure 9 below illustrates, almost all oil produced in New Zealand is exported, with New Zealand's domestic oil consumption being almost entirely met through importing oil from overseas (being a mixture of unrefined oil which is then processed in the Marsden Point refinery, and already refined oil products (i.e. diesel, petrol, aviation fuel etc.)).

[18] Data on domestic gas consumption from a number of sectors is not available prior to 1990.
[19] Much of the differences is understood to be due to statistical measurement & reporting issues.

Figure 9: Historical production, consumption, imports and exports of oil[20]



Source: Concept analysis using MBIE data

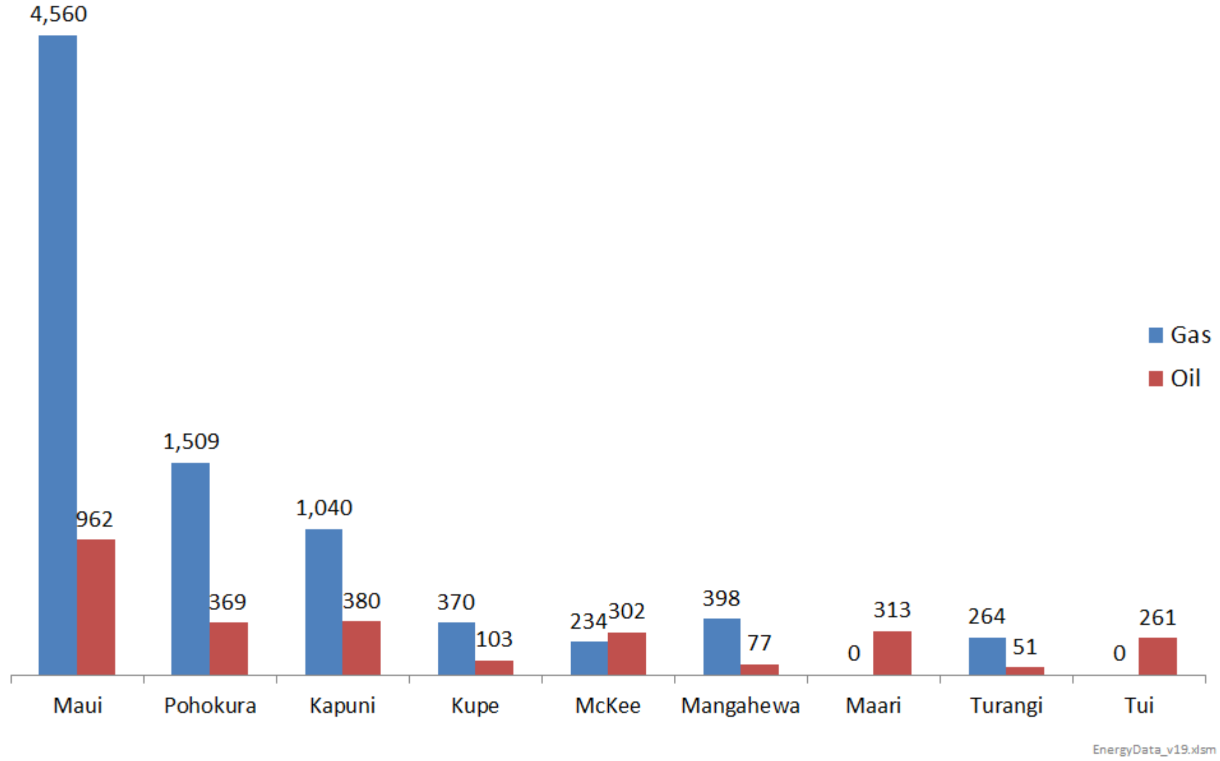
The fact that any gas produced in New Zealand must be consumed domestically has implications for the economics of exploration and production. In particular, an upstream producer must have confidence that it can commercialise any gas that is found through selling to New Zealand-based gas consumers.

This is not just an issue for gas exploration, but also for oil exploration and production given that for many New Zealand fields, gas and oil are found and produced together. This can be seen by looking back at Figure 6 and Figure 7 and comparing the historical pattern of gas and oil production for a number of the fields– e.g. the historical pattern of production at the Maui, Kapuni and Pohokura fields has been very similar between oil and gas. These issues are explored further later in this section.

[20] For the purposes of this illustration the 'consumption' line has been derived as being equal to: Production + Imports – Exports. In reality consumption is more complicated as there can be material year-to-year stock changes, and the need to account for aspects such as fuel consumed by international transport (ships + planes)

The extent to which gas and oil are found at the same fields is further illustrated in Figure 10 below which shows the proportion of oil and gas for ultimately recoverable reserves for nine of New Zealand's largest fields. It shows that all of New Zealand's significant gas-producing fields are gas-*condensate* fields. i.e. there are material quantities of liquids in these fields.

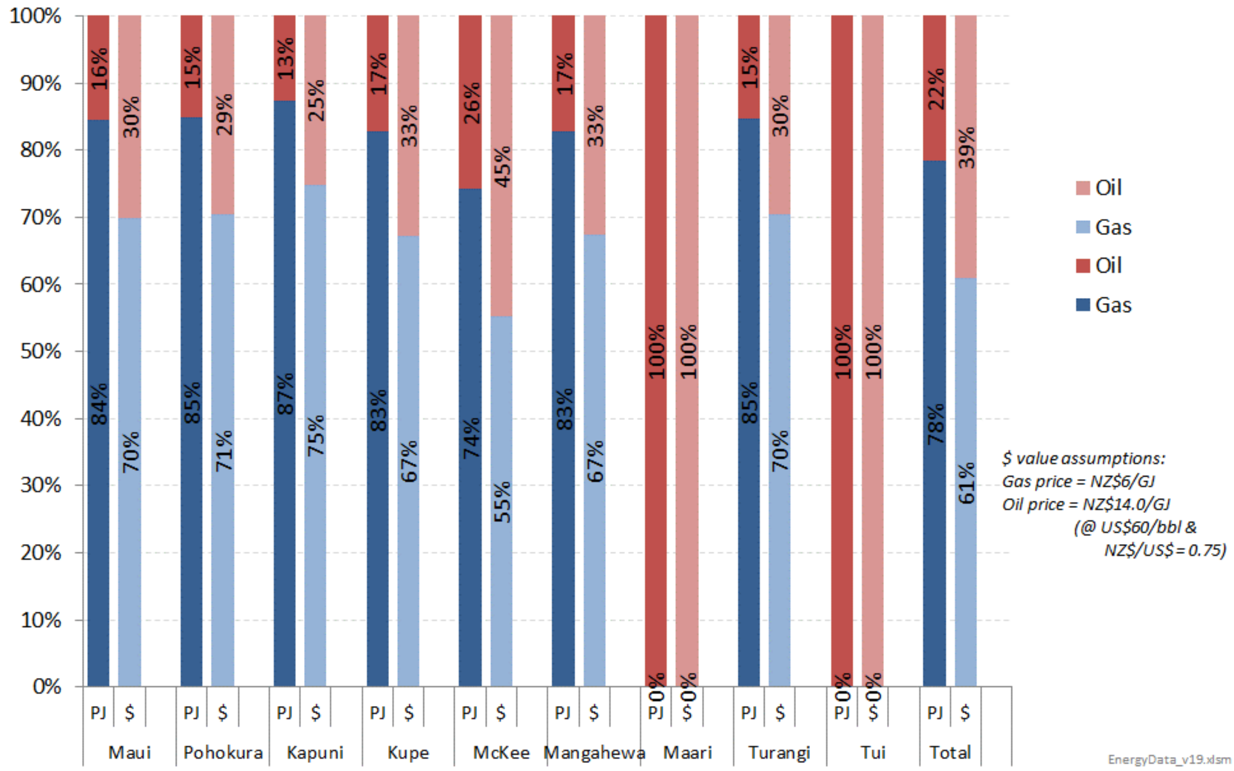
Figure 10: Estimated P50 probability ultimately economically recoverable oil and gas reserves as at 1 January 2015 (PJ)



Source: Concept analysis using MBIE data

Figure 11 below shows the same data but on a proportional basis, plus including an estimate of the proportion of the relative *value* of the gas and oil for a given assumption about oil and gas prices (the right-hand bar for each pair of bars).

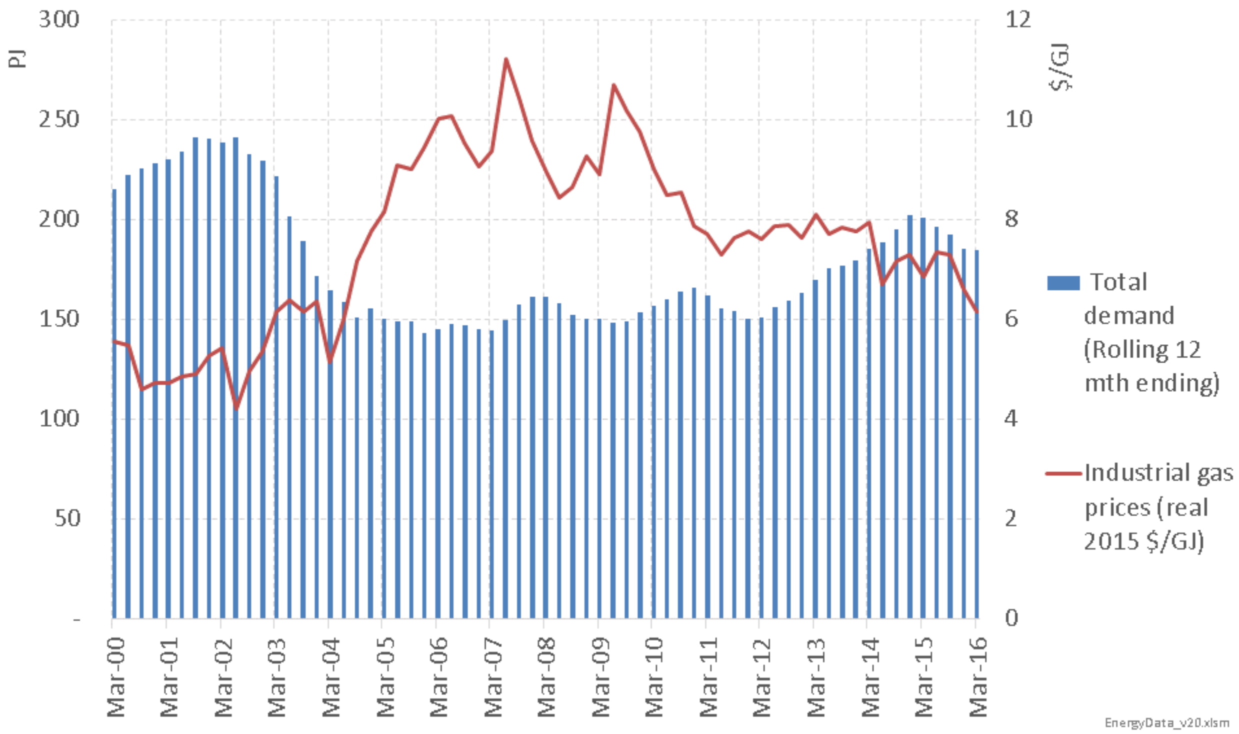
Figure 11: Proportional split between oil and gas reserves and value for main New Zealand fields as at 1 January 2014



Source: Concept analysis using MBIE data

As indicated by Figure 12 below, gas prices and demand in New Zealand have experienced significant variation over the past fifteen years. After a period of relatively low prices and high demand at the start of the 2000's, gas prices rose sharply in the first half of the last decade closely followed by a significant drop in demand. More recently, wholesale gas prices have fallen significantly and demand has once again started to rise.[21]

Figure 12: Historical New Zealand gas demand and industrial gas prices[22]



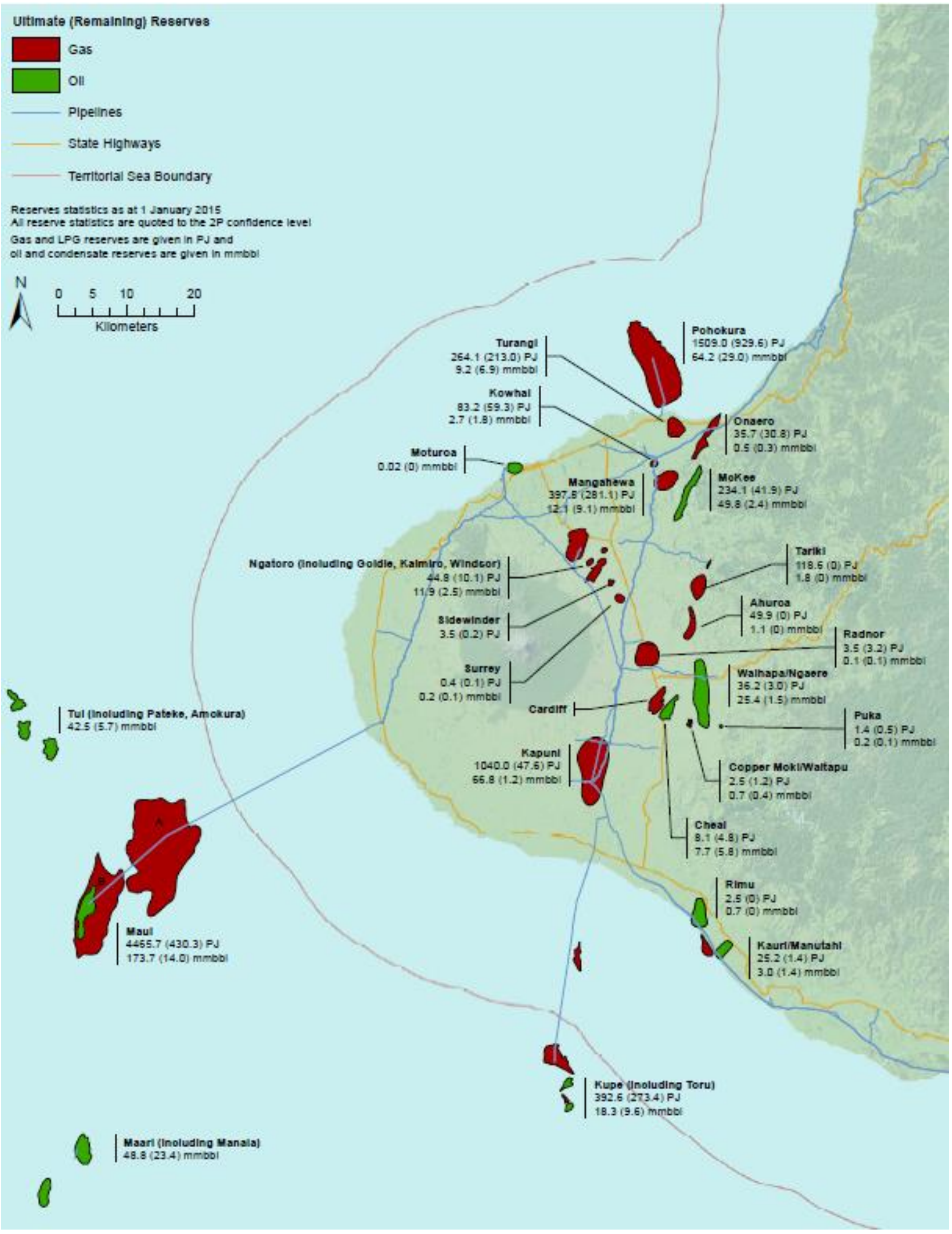
Source: Concept analysis using MBIE data

3.3 Current gas production

All of New Zealand's existing gas production is from gas-condensate fields in the Taranaki basin as shown in Figure 13. The three largest producers (Pohokura, Maui and Kupe) are all offshore fields, and the balance of production comes from smaller onshore fields.

[21] The fall in demand over the last

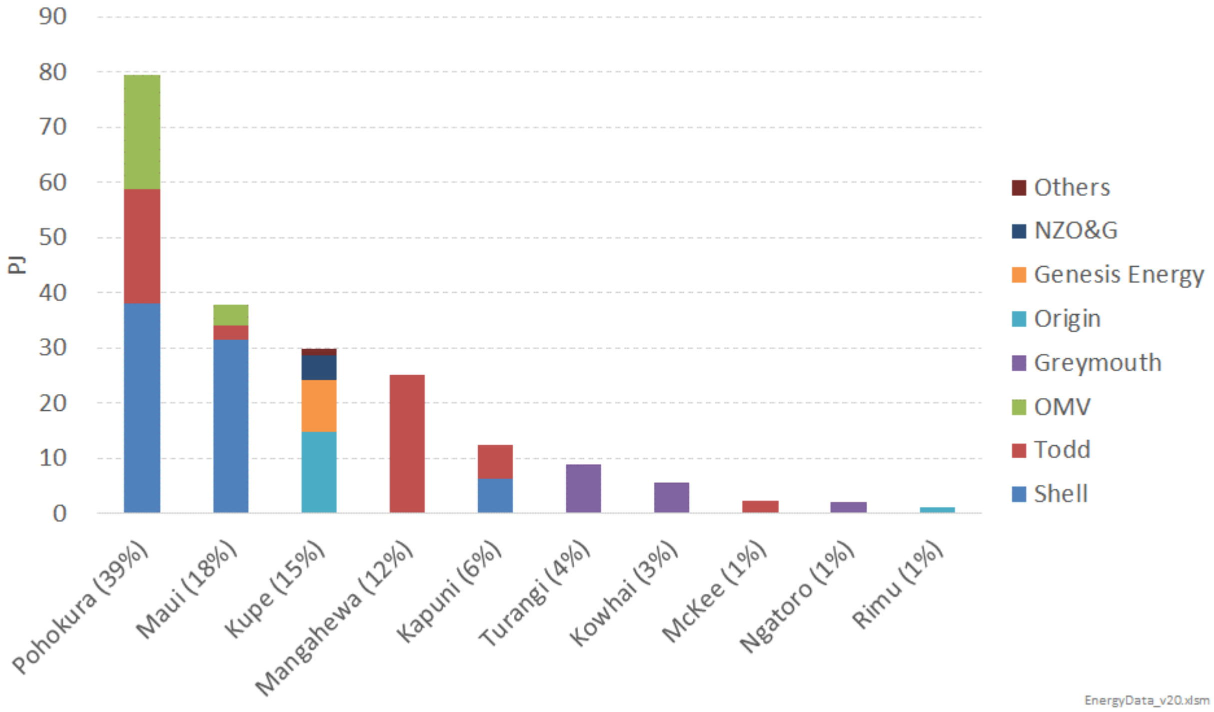
Figure 13: Gas-condensate and oil fields in Taranaki



Source: MBIE

Figure 14 shows the most recent annual gas production data across major fields, and the producer participants for each field. While Maui still makes a significant contribution to overall production, supply is now much more diversified across multiple sources than in the past (see Figure 6).

Figure 14: Field production for 2015



Source: Compiled from MBIE data. Gross data excluding offshore Tui and Maari fields not linked to gas pipeline network.

3.4 Gas reserves and contingent resources

The Crown Minerals (Petroleum) Regulations 2007 require gas producers to report on remaining reserves and resources. Reserves and resources provide measures of the gas inventory based on already *discovered* accumulations of gas.

Reports on reserves and resources must be compiled in accordance with the internationally recognised Petroleum Resources Management System (PRMS), published by the Society of Petroleum Engineers (SPE).

Under the SPE classification system:[23]

- Reserves are defined as known accumulations of petroleum, which are anticipated to be both technically and commercially recoverable.
- Contingent resources are defined as estimates of recoverable quantities from known accumulations which do not fulfil the requirement of commerciality at present. The definition of commerciality for an accumulation will vary according to local conditions and circumstances.

The SPE also defines prospective resources, which are quantities of petroleum which are estimated, on a given date, to be potentially recoverable from *undiscovered* accumulations.

Within reserves and contingent resources, there is further subdivision based on the assessed level of uncertainty associated with an estimate. A P50 reserves figure represents a mid-point estimate of reserves (also known as 'probable'), while a P90 figure (also known as 'proved' or 1P) reflects an estimate with a 90% level of confidence, whereas a P10 figure (also known as 'possible' or 3P) reflects

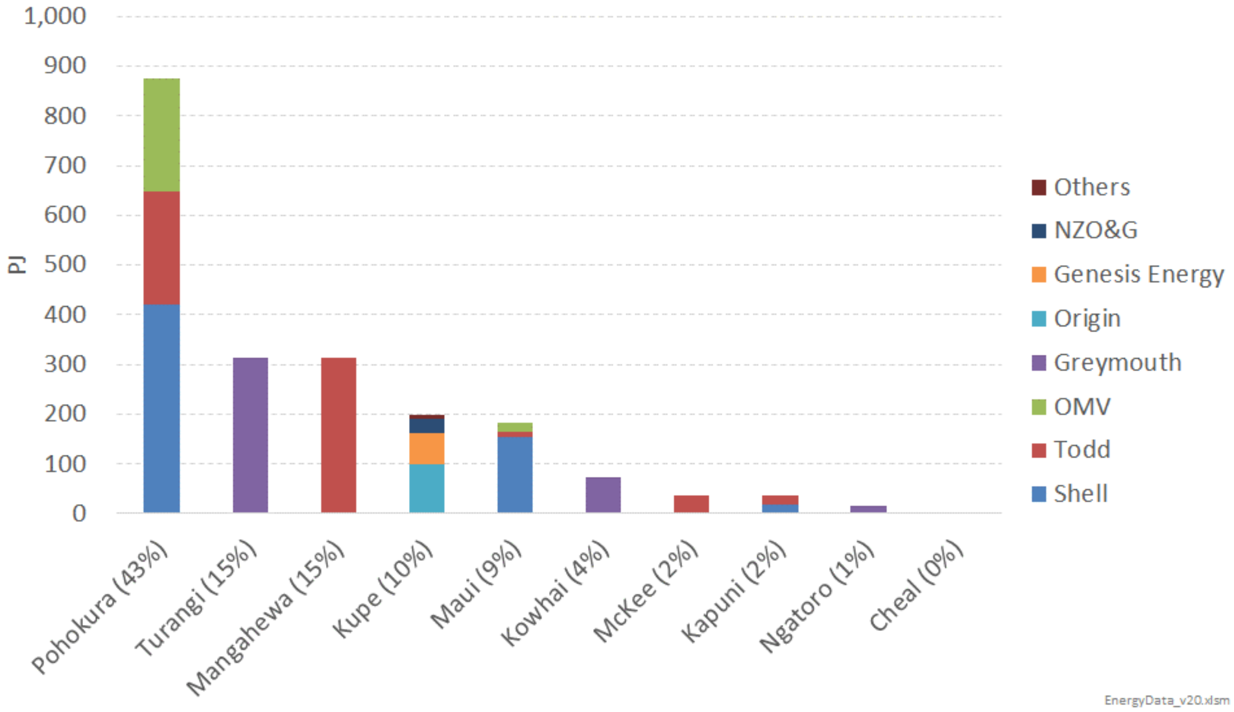
[23] See http://www.spe.org/industry/petroleum-resources-classification-system-definitions.php. Reference should be made to the full SPE/WPC Petroleum Reserves Definitions for the complete definitions and guidelines.

an estimate with a 10% level of confidence. Similarly, contingent resources are categorised by the SPE into 1C, 2C and 3C according to level of uncertainty.

3.4.1 Gas reserves

Figure 15 shows New Zealand's remaining gas reserves assessed on a P50 basis. Around 75% of New Zealand's remaining P50 reserves are in fields developed since 2000. The exceptions in age terms are Maui (first production 1979 – 9% of remaining reserves) and Kapuni (1974 – 2% of remaining reserves).

Figure 15: Field reserves (remaining recoverable P50 estimates) and ownership as at 1 January 2016

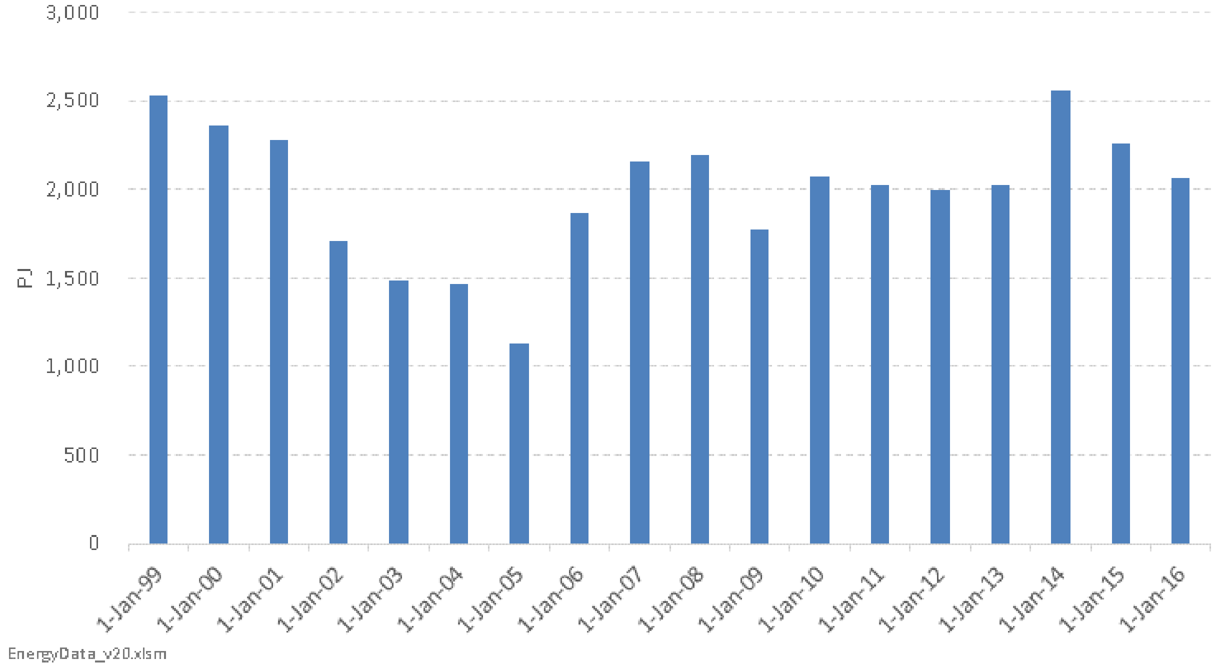


Source: Compiled from MBIE data.

Figure 16 shows the assessments of the remaining P50 gas reserves over the period since 1999. It shows the decline in remaining reserves in the early 2000s associated with the redetermination of the Maui field, followed by the strong recovery since that time. This reflects the significant exploration and development activity in the last decade, which has resulted in growth and then ongoing replacement of P50 reserves. In particular, the development of the 1,500 PJ Pohokura gas field in 2008, and the 370 PJ Kupe field in 2010.

Over the past two years, reserves have declined following a drop off in exploration effort (and success) but with demand continued at high levels (approximately 180 PJ/yr). Further, the most recent reserves numbers are also likely to reflect the low oil and gas prices, noting that the P50 classification refers to whether reserves are likely to be technically *and commercially* recoverable.

Figure 16: Remaining P50 gas reserves[24]



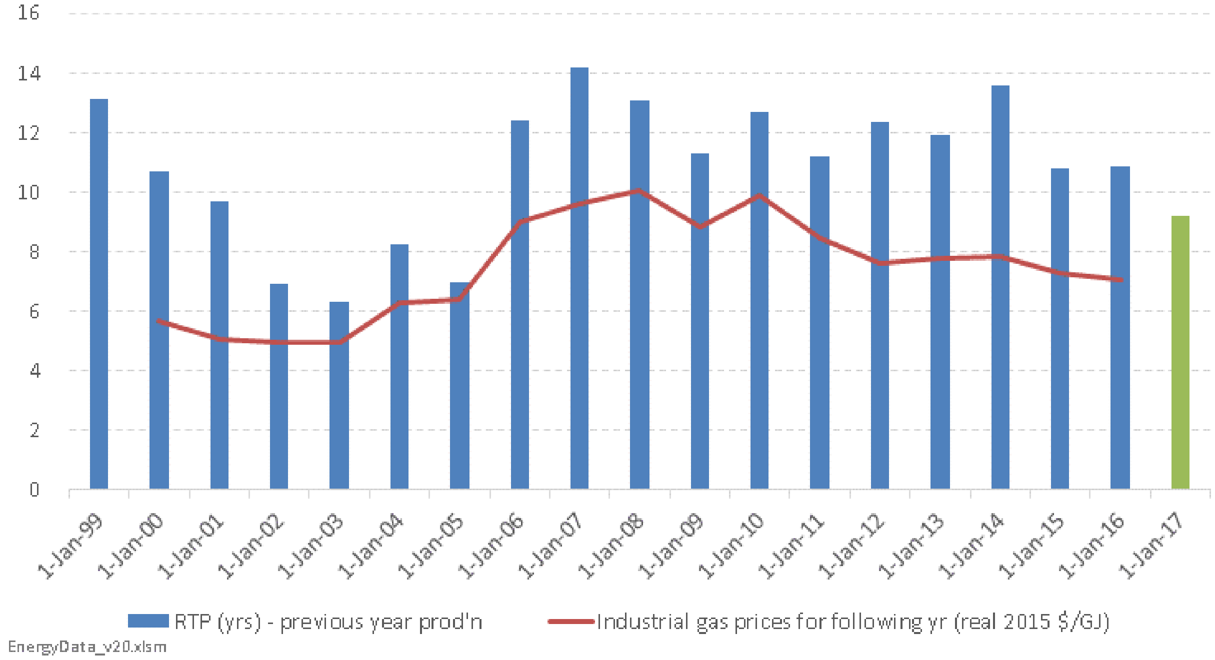
Source: Concept analysis using MBIE data.

[24] The chart is based on published MBIE data. However, it is not clear whether consistent definitions of 2P reserves have been applied through the period. For example, reserves are reported for Kupe from 1999, which was long before any final investment decision was made to develop the field. Reserves figures also show marked shifts in the mid-2000s for reasons which are not clear.

3.4.2 Reserves to production ratio

Figure 17 shows the track of the RTP ratio since 1999, based on P50 reserves data. The 1 January 2017 value is based on an estimated production value of 200 PJ for 2016, and assuming that there are no new reserves booked during 2016. The chart also shows the reported real average gas price paid by industrial customers.[25]

Figure 17: P50 reserves to production ratios and gas prices[26]



Source: Concept analysis using MBIE data.

As noted above, there was a marked tightening of gas supply in the early 2000s (denoted by a fall in the RTP ratio) caused by the redetermination of Maui reserves. The contraction in supply led to a period of rising gas prices, and is reflected in the average prices paid by industrial consumers.

By the mid-2000s major new fields were being committed for development. In particular, the RTP ratio rose from 2008 with the development of the Pohokura and Kupe fields. This was accompanied by a reduction in gas prices for industrial users after 2008, reflecting an easing of tight supply conditions.

Since that time the RTP ratio has been around 10-12 years, reflecting changes in both gas reserves and the rate of gas usage. For example, Methanex had scaled back its use in the mid-2000s when supply was tight and prices were higher. Since 2010, there has been a progressive increase in gas usage by Methanex.

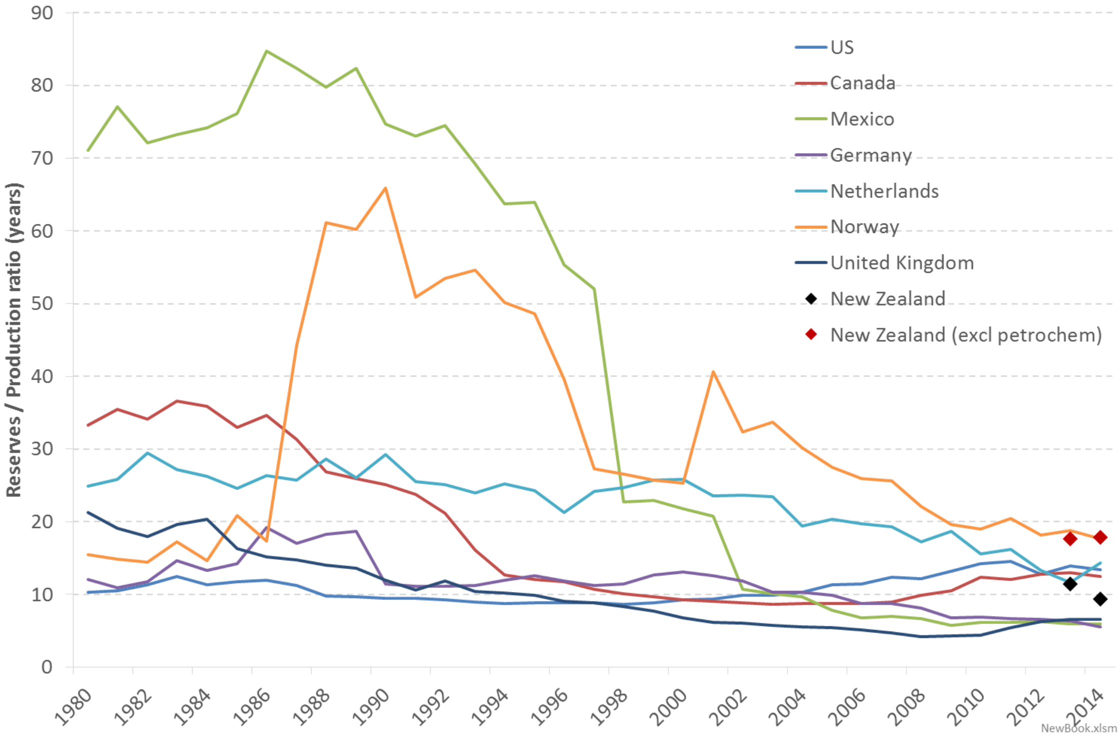
The significant drop from 1-Jan-14 to that projected for 1-Jan-17 is due to no material new reserves being booked yet demand continuing at relatively high levels. Further, the most recent reserves data also includes some downward revisions for the Maui field – presumably reflecting that view that the *economically recoverable* quantity of reserves is lower due to lower oil and gas price expectations.

[25] The industrial gas price included is compiled by MBIE based on data supplied by gas retailers. Prices are not available for calendar 2016.

[26] Prices for industrial consumers include transport (i.e. pipeline network) costs. The prices should therefore be taken as indicative of trends in the underlying commodity wholesale gas price, rather than the level per se.

Figure 18 compares New Zealand RTP ratios with those for a range of other gas-producing countries. Note that in this case the data is for P90 or proven gas reserves.[27]

Figure 18: International comparison of RTP ratios – based on proven (P90) reserves



Source: Concept analysis using data from MBIE and BP

The chart shows a general tendency for RTP ratios to be around the 10-20 year range. This reflects the likelihood that countries with relatively high RTP ratios (such as Norway or Mexico) tend to develop additional demand sources such as gas exports via pipelines or LNG supply, or petrochemical production which export the gas in the form of products such as methanol or urea. These additional demand sources have the effect of lowering their RTP ratios over time. Likewise, in countries with a lower than average RTP ratio, there is likely to be an increased incentive to identify and commercialise new gas reserves, or extend existing reserves life by reducing demand from lower value uses of gas.

The chart also shows New Zealand data depicted by dots. On this RTP measure, New Zealand has had around 10-12 years cover in recent years, which is within the central part of the range for the countries reported.

Another measure of RTP ratio for New Zealand would be to exclude gas usage for petrochemical production, on the basis that this is more discretionary, and would probably be reduced if gas prices rose due to tight supply. This alternative measure indicates around 18 years of cover, which would be toward the upper end of the reported range.

3.4.3 Contingent resources

From 2014, the government introduced a requirement for permit holders to report on contingent resources – i.e. hydrocarbon accumulations that are identified as being likely to exist, but which are presently uneconomic to develop given the current oil and gas price outlook. Table 2 shows the most recent reported data on contingent resources. In terms of gas, almost all of the contingent resource is within existing producing fields in Taranaki. Over 50% of the total is within the onshore Kapuni field.

---

[27] This chart is based on proven (or P90) reserves because data on P50 reserves for other countries was not readily available. The New Zealand data is for remaining P90 gas reserves. The New Zealand data also includes LPGs for all fields. This chart is therefore not directly comparable with the data shown in Figure 17.

Table 2: Contingent resources reported as at 1 January 2016

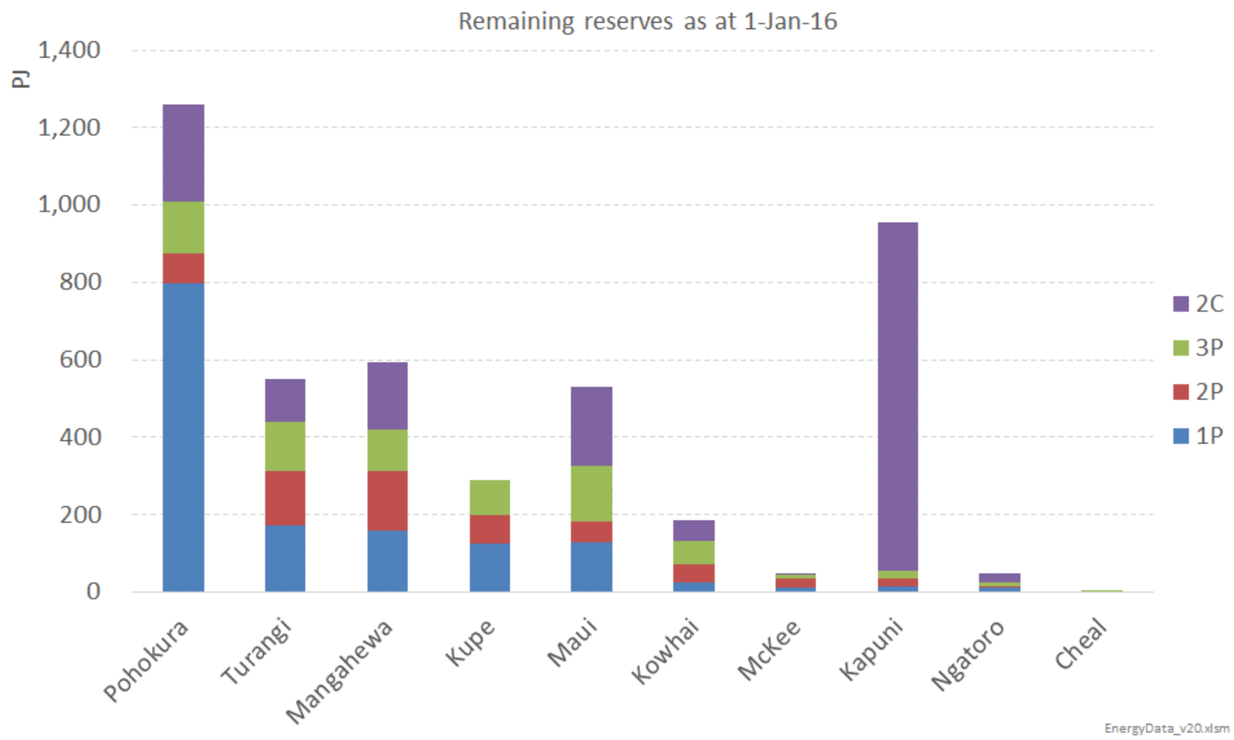
	Contingent resources[1]			
	Oil (million barrels)	Condensate (million barrels)	LPG (1,000 tonnes)	Gas (PJ)
Kapuni		32.6		900.9
Maui*	5.4	8.0	155.0	203.7
Pohokura		6.4		249.8
Mangahewa		3.6		173.2
Turangi		2.7		110.2
Maari	16.2			
Kowhai		3.4		53.4
Ngatoro	5.6	0.4		24.9
Kauri				16.7
McKee	2.6			0.7
Total	**29.9**	**57.1**	**155.0**	**1733.5**

[1]Estimated quantities, at a given date, potentially recoverable from known accumulations, but for which the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies.
*Crude Contingent Resources from Ruru permit only. Condensate and gas from Maui and Ruru included. LPG from Maui.

Source: MBIE

Figure 19 shows reported gas reserves/resources as at 1 January 2016 at differing levels of classification. The 2C resource estimate is similar in magnitude to the 2P reserves.

Figure 19: Remaining gas reserves/resources as at 1 January 2016 at differing levels of classification.



Source: Concept analysis of MBIE data

3.5 Outlook for gas supply

In physical terms, there are many potential sources of supply to meet gas demand in New Zealand – these include:

- Existing or new fields in the Taranaki basin
- New fields in one or the more of the 17 other petroleum basins across New Zealand
- Unconventional gas sources
- Imported gas.

Each of these is discussed further in Appendix A. Given the wide range of potential physical supply sources, the outlook for gas supply is primarily an economic issue. This in turn is influenced by a number of drivers including:

- The price of crude oil
- The demand for gas from users within New Zealand, most importantly petrochemical production and power generation, discussed further in section 4 and 5
- Carbon prices.

3.5.1 Oil price outlook affects gas supply

An important feature of New Zealand's gas sector is the strong influence of liquids[28] on sector economics. All of New Zealand's existing gas is produced from gas-condensate fields, with liquids often accounting for a material component of reserves in energy terms. Prices for condensates are typically strongly correlated with the crude oil prices. Condensates are generally more valuable than gas on an energy equivalent basis.[29] These factors mean that the economics of gas-condensate field development and production in New Zealand are strongly influenced by crude oil prices. Other factors can also be important (especially gas prices).

The influence of oil prices on New Zealand upstream activity is illustrated by Figure 20. It shows a generic measure of upstream 'effort' – being the total wells drilled each year, along with trends in real oil prices over time. The chart shows the progressive rise in oil prices from 2002 to 2008, followed by an increase in supply-side activity. No data is available for the number of wells drilled in 2016, but the year-to-date oil price is shown.

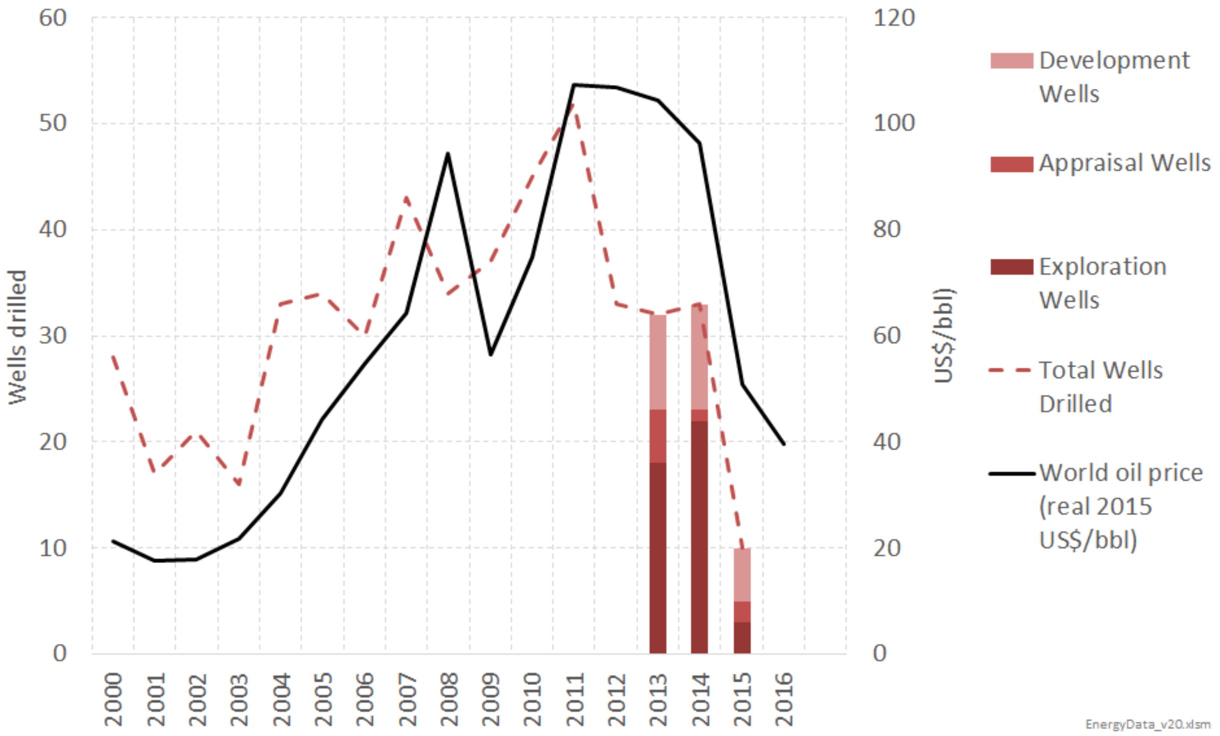
Oil prices fluctuated in the period 2008-2014 but generally remained above $US60/bbl (real). During this period, supply-side expenditures continued at relatively strong levels compared to the earlier historic average.

Since 2015, oil prices have been much lower. New Zealand upstream participants have generally reacted by reducing or delaying discretionary spending as shown by the sharp drop in the number of wells drilled in 2015 – particularly for exploration.

28 This includes crude oil and other hydrocarbon fluids in the well production stream that are liquid under normal conditions, such as naphtha, light oil and natural gasoline. The terms liquids, oil and condensates are sometimes used inter-changeably.

29 For example, one barrel of oil has 5.8 GJ of energy. If the price of oil is US$50 per barrel, this means oil has a value of US$8.60/GJ in energy equivalent terms.

Figure 20: Upstream activity and oil prices



Source: Concept analysis of MBIE and World Bank data

Exploration and development activity is expected to remain at reduced levels until there is a strengthening in the outlook for oil prices. This reduced activity in turn is expected to contribute to a tightening of gas supply in New Zealand, all other factors being equal.

This fall in New Zealand exploration mirrors similar drops in activity worldwide. Information released by the International Energy Agency in September said that oil and gas-field spending fell 25% in 2015 and is set to drop by a further 24% in 2016. And the IEA's executive director, Fatih Birol, was reported as speculating that "*It may well be the case that investment will fall in 2017. We have never seen (a three-year decline) in history*".[30]

Factors other than the oil price outlook will also influence exploration effort in New Zealand. For example, New Zealand's relatively remote location increases costs – other the hand it is perceived as having a relatively stable regulatory regime and supportive fiscal settings.

The gas reserves reported as at 1 January 2016 show a material reduction since the previous annual data, because of two factors:

- Relatively high production in the intervening period, but with limited new additions to reserves; and
- Because reserves must by definition be assessed as economic to recover, the weaker outlook for oil prices (compared to earlier periods at least) is likely to affect the reserves assessment of previously discovered hydrocarbon accumulations.[31] This is particularly apparent in the reserves assessment for the Maui field which has seen a decline in assessed reserves of several hundred PJ.

This highlights the likelihood of a negative correlation between oil and New Zealand gas prices over time. This arises because lower oil prices make New Zealand's exploration and development activity relatively more dependent on gas revenues (requiring higher average gas prices), and vice versa. That said, oil and gas are also partial substitutes in some circumstances. For example, if New Zealand were to

30 "*Oil, gas investment continues to tumble*", The Australian, 15 Sep 2016

31 Assuming producers have a lower expectation of oil prices than when they last reported reserves.

develop an export-oriented LNG industry based on a major gas discovery, gas prices might become positively correlated with oil prices.[32]

This raises the broader question of where oil prices are likely to trend in future. The fall in the oil price that has been seen since 2014 is widely attributed to rising United States production from unconventional sources, coupled with determination by members of the Organisation of Petroleum Exporting Countries (OPEC) to defend their existing markets. This sparked a steep decline in oil prices, falling below US$30/bbl in early 2016. Many commentators expected low prices to drive much of the unconventional United States capacity out of the market. However, United States production has proven to be more resilient than many expected, with the significant production cuts not materialising (though growth has flattened off).

Looking ahead, many major forecasters are expecting some recovery in oil prices off the back of rising global demand. However, the trajectory and end-point is far from certain. For example, the IEA has recently stated that: [33]

> *"Attempting to understand how the oil market will look during the next five years is today a task of enormous complexity. Some certainties that have guided our past outlooks are now not so certain at all."*
>
> *"It is very tempting, but also very dangerous, to declare that we are in a new era of lower oil prices. But at the risk of tempting fate, we must say that today's oil market conditions do not suggest that prices can recover sharply in the immediate future"*
>
> *"Only in 2017 will we finally see oil supply and demand aligned but the enormous stocks being accumulated will act as a dampener on the pace of recovery."*
>
> *There is a "risk of a sharp oil price rise towards the later part of our forecast arising from insufficient investment."*
>
> *"In 2016, we are living in perhaps the first truly free oil market we have seen since the pioneering days of the industry."*

In a report released in June 2016, McKinsey & Co asked "Is peak oil demand in sight?". [34] McKinsey raised the question after lowering its long-term demand forecast for oil, citing factors such as the projected uptake of autonomous and electric vehicles, and structural changes in the global economy – especially a rising share of services.

The uncertainty about future oil prices is evident in recent projections published by international forecasters as at May 2016, which is shown in Figure 21. The forecasters are all projecting an increase from the low levels recorded in early 2016, but the size and speed of the rebound varies widely.

For 2020, the projections range between approximately US$45 (IMF) and US$80/bbl (EIA). The World Bank is projecting prices to be around US$60/bbl, which is broadly consistent with the prices for futures contracts for that period.

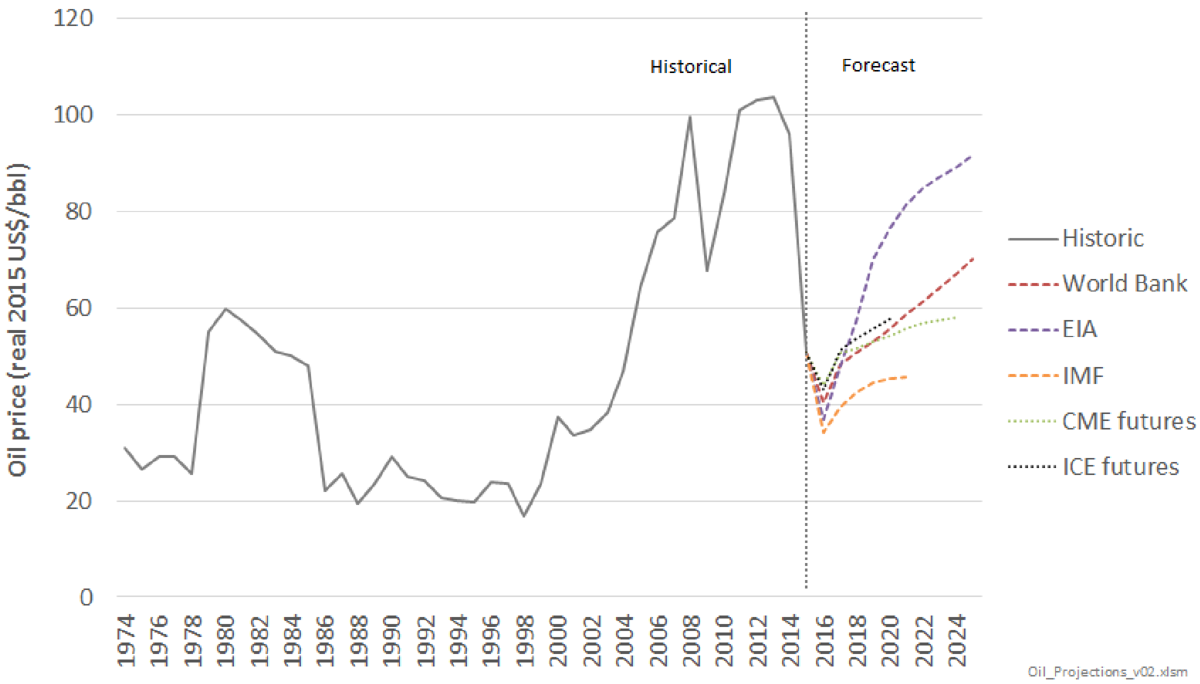
---

[32] In principle, the observed historic correlation between oil and methanol prices might have a similar influence, although this is expected to be weaker because the relationship is less direct.

[33] See International Energy Agency, Medium-Term Oil Market Report, 2016

[34] See www.mckinsey.com/industries/oil-and-gas/our-insights/Is-peak-oil-demand-in-sight?cid=other-eml-alt-mip-mck-oth-1607

Figure 21: Oil price projections



Source: Concept analysis of data from various sources. Note that forecasts may differ slightly in their basis.

Returning to the New Zealand supply outlook, a key question is what *expectation* producers will have for future oil prices, since that affects decisions by upstream participants about how much effort to apply to exploration and development.

Based on views of major international forecasters, it appears reasonable to expect some recovery in oil prices – albeit to levels below the US$100/bbl mark. For example, a recovery to US$60/bbl would be a significant lift compared to prices recorded in H1 of 2016.

At that price, it is likely that global hydrocarbon exploration effort will increase – albeit to lower levels than seen during the period of US$100/bbl prices. Another key issue is where New Zealand sits relative to other international locations for hydrocarbon exploration. While New Zealand has some drawbacks due to its remote location and small domestic market, the Taranaki basin does have a number of positive attributes as a place for exploration effort, these are:

- There is existing oil & gas infrastructure for exploration and production which lowers the cost of developing new fields
- It is not too challenging an environment compared to other locations (with the exception being very deep-water Taranaki)
- Taranaki is still relatively lightly-explored, and thus has reasonable prospectivity
- New Zealand has a stable political and attractive regulatory regime compared to many other international jurisdictions.

Thus, there is a reasonable likelihood that a strengthening in oil prices will lead to be some recovery in exploration and development effort in the Taranaki basin – albeit, not necessarily to the historically high levels seen a few years' ago.

However, no one knows for sure if recent oil price weakness is an aberration, or a sign of the future. If the oil price recovers, that will rekindle upstream activity and assist in rebuilding gas inventories. Conversely, if the oil price outlook remains weak, upstream activity will be subdued, putting upward pressure on gas prices.

3.5.2 Demand for gas within New Zealand

As noted earlier, New Zealand's gas market is relatively unusual by international standards because it is physically isolated from any major external demand sources.[35] As a result, gas producers are entirely reliant on domestic gas users for sales. Furthermore, increments of supply (or demand) can be relatively lumpy relative to the overall market size – as a result, decisions about some individual supply (or gas-using plants) can materially affect the supply/demand balance.

Having said that, some categories of gas user tend to act as 'market balancers' – increasing or scaling back their level of demand in response to prevailing market conditions. As such, these categories of gas user have been key enablers of the upstream gas (and oil) industry in New Zealand – providing sufficient confidence for upstream explorers that if they find gas in association with oil they will have a means of readily monetising it, while at the same time providing the flexibility to scale back at times of relative scarcity to ensure gas reserves are prioritised for the highest value uses of gas.

As is illustrated in Figure 22 below, historically the two most important sources of such 'market balancing' have been:

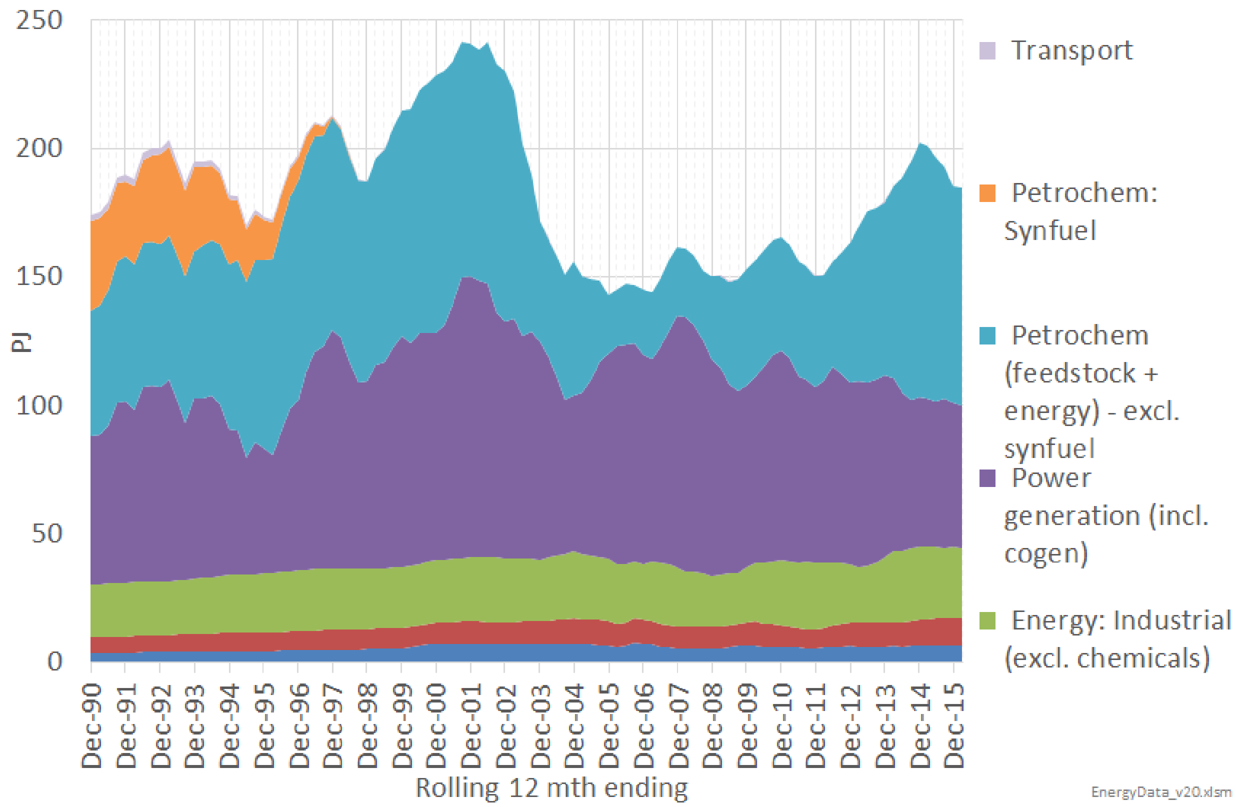
- Petrochemical production – especially gas use for methanol production. This is both a large and relatively responsive source of gas demand – accounting for between 16-49% of total gas annual demand over the last decade. Methanol production effectively provides a means of exporting gas (as methanol) when there is sufficient gas supply in New Zealand to make this economic. The existing methanol plants are expected to be available to operate in this type of manner for most or all of the projection period – and this is discussed further in section 4. This does not mean that they will necessarily *operate* – that will depend on the availability of gas at competitive prices. Nonetheless, the presence of the plants provides a large 'anchor' customer for gas explorers – which tends to support upstream effort. While it is possible that these plants could be relocated offshore if there was sustained tight gas supply in New Zealand, such a change is likely to occur over a very extended period – as has occurred in Chile. So the market balancer role appears secure for the foreseeable future.

- Power generation – historically there has been some ability for power generation to switch between gas and coal-fired operation.[36] In particular, this occurred during the mid-2000s when gas supply was relatively tight. While this source of balancing has been important in the past, it is less significant now, and is not expected to deliver the same amount of flexibility in the future. That said, as the analysis in section 5 details, it is expected that the power generation sector may still offer a reasonable amount of long-term balancing (i.e. reducing or increasing demand in response to relative scarcity or surplus in the upstream gas position) in terms of the extent to which renewables are built to displace existing gas-fired generation plant from higher capacity-factor duties.

[35] New Zealand does not have any pipeline interconnections with other countries. Nor does it have any terminal for the import or export of liquefied natural gas (LNG) by ship.

[36] Switching can occur within the dual coal- and gas-fired Huntly power station, and by using more/less coal at Huntly and less/more gas at other stations.

Figure 22: Historical sectoral gas demand - area graph



Source: Concept analysis using MBIE data

In essence, gas supply and demand decisions can be highly inter-related for these gas users. This issue is discussed further in sections 4 and 5, which address projected demand for gas from petrochemical manufacturers and power generation.

In contrast, direct use of gas for energy (residential, commercial, and industrial) has not shown the same degree of responsiveness to New Zealand's changing up-stream gas position. This reflects the fact that:

- Fuel costs generally comprise a relatively small proportion of total factor input costs for such consumers, and thus demand is not very sensitive to changes in fuel costs. This results in such users typically being the highest value users of gas.
- The wholesale component of gas costs is generally a relatively small proportion of the total costs of delivered energy, reflecting the fact that transport costs and appliance capital costs comprise a relatively large proportion of the total cost of useful energy.

3.6 Greenhouse gas emissions

There is an increasing global focus on the importance of reducing greenhouse gas emissions. This was evident at the Paris Summit in December 2015, when 195 countries reached consensus on a set of principles and targets intended to limit climate change-induced temperature rise to "well below" 2 degrees Celsius.

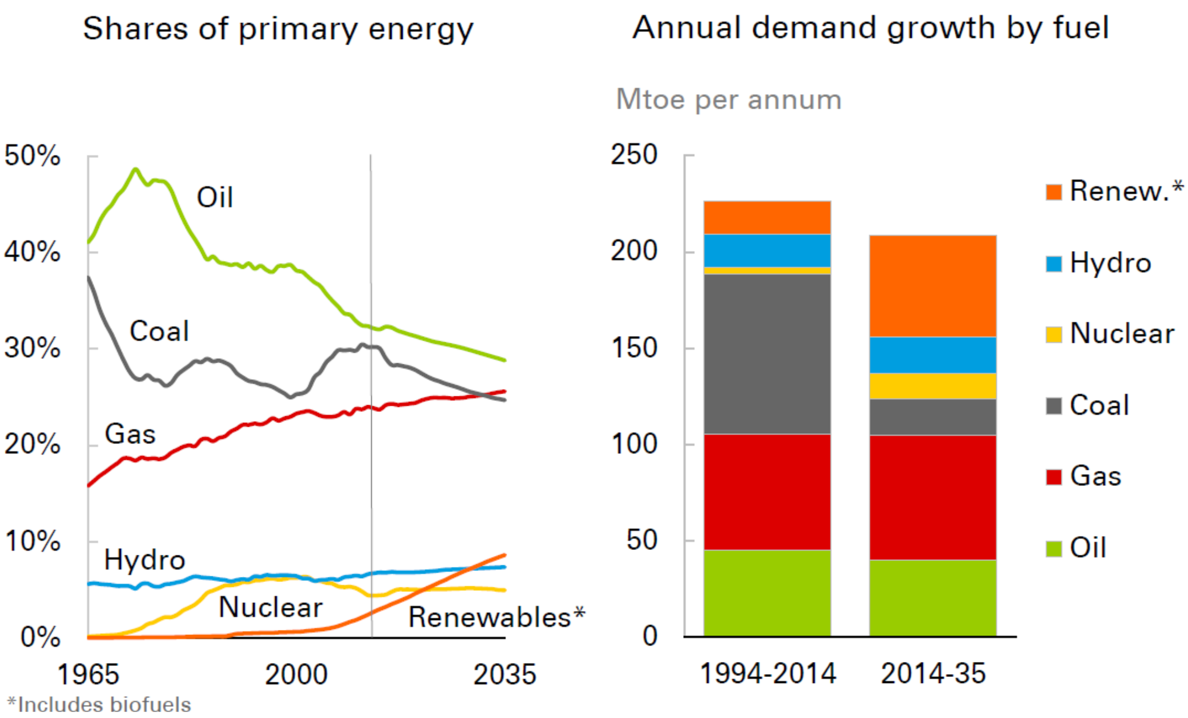
On the global stage, this strengthening focus on greenhouse gas emissions is expected to have two broad effects on the gas industry:

- Over the next couple of decades, gas is expected to displace more carbon-intensive energy sources, especially coal, but also oil. This is likely to result in an increase in gas consumption, particularly in the power generation sector.

- Looking out further, gas use is expected to reduce over time, as it is displaced by less carbon-intensive energy sources, such as renewables (for electricity generation), and biofuels for direct-use applications.

The first of these two effects is expected to dominate internationally over the next couple of decades, as gas provides a 'bridge' to a lower carbon future. For example, BP projects gas and renewables to be the only two energy sources that will experience market share growth over the next 20 years – as shown in Figure 23.

Figure 23: Gas versus other energy sources – global projections



Source: BP Energy Outlook 2016

This global backdrop will also have implications on gas in New Zealand across a number of dimensions:

- demand for direct use
- demand for power generation
- demand for petrochemicals
- upstream exploration.

3.6.1 CO_2 implications on direct use of gas for energy

The recent Consumer Energy Options[37] study presented analysis on the economics of gas for the three main direct uses of gas:

- Industrial process heat
- Space heating
- Water heating

Amongst other things, the study considered the potential implications of higher CO_2 prices. The analysis is not repeated here, but the key conclusions were:

[37] The Consumer Energy Options report and associated stakeholder presentation is available here: http://gasindustry.co.nz/about-us/news-and-events/events/release-of-consumer-energy-options-in-new-zealand-2016-update-by-simon-coates/

Industrial process heat

The analysis found that gas is very competitive for industrial process heat, with coal being the main competition for the largest process heat uses (which dominate overall process heat demand). In the North Island, gas has largely displaced coal except from a few specific close-to-mine mouth facilities. Higher CO_2 prices would likely result in additional fuel switching away from coal to gas, and such an increase would represent around 1-2% of current gas demand.

In the South Island there is considerable use of coal by users for industrial heat purposes. At present it is challenging for these users to substitute to lower carbon fuels due to the lack of reticulated natural gas in the South Island, and the relatively high cost of biomass. However, gas has been discovered in the offshore Canterbury basin. Sale of gas to industrial users in parts of the South Island may prove to be commercially attractive way to develop these resources, while also offering emission benefits.

Generally, biomass was found not to be economic in most situations due to much higher boiler capital & operating costs compared to gas, and the much higher delivered fuel costs for most situations (the exception being the wood processing industry where biomass is essentially available on site and is effectively 'free'). Further, the scale of biomass required to switch away from coal and gas for industrial process heat is considered to be too large to be practicable for the foreseeable future, even with much higher CO_2 prices.[38]

That said, in the very long term, it is possible that developments in electromechanical technologies (e.g. heat pumps, microwave technologies, etc.) may start to provide economic alternatives to gas and coal for some process heat requirements (e.g. drying). However, these are understood to be quite a long way off from being economic.

Accordingly, for the foreseeable future, higher CO_2 prices will tend to support gas demand for industrial process heat, but the level of increase is likely to be small relative to the overall market size. There is one important caveat to this conclusion. It is based on the assumption that industrial customers exposed to overseas competition will continue to be largely shielded from the domestic carbon price, to maintain their competitiveness against countries that haven't introduced a CO_2 price.[39] To the extent that such a mechanism were removed, it is possible that some relatively energy-intensive process heat consumers may reduce or cease their operation (with the production effectively moving overseas to more CO_2-intensive locations). This would have a knock-on effect on gas demand.

Space and water heating

For space and water heating, carbon comprises a relatively small proportion of overall costs. Accordingly, even with relatively high CO_2 prices, the price impact on gas heating was identified to be modest – particularly given that electricity generation is also relatively fossil-fuel intensive at times of high demand.

That said, the high efficiency of heat pumps makes them less fossil-fuel intensive than direct use of gas applications, and there is a general public perception that New Zealand's electricity is predominantly renewable – even when on a *marginal* basis that is often not the case. Accordingly, it is possible that a high CO_2 price future, and the associated heightened public awareness of greenhouse issues, may result in greater consumer switching away from gas than would be expected purely on the basis of altered consumer prices.

---

[38] For example, one industrial representative estimated that it would require a forest area the size of Belgium (approximately 15% of the South Island land mass) to switch away from coal to biomass for industrial process heat).

[39] At the moment, this is achieved under the New Zealand Emissions Trading Scheme (NZ ETS) through Emissions-Intensive Trade Exposed businesses receiving counter-balancing 'compensation' up to 90% of the level of the increased costs they face through the NZ ETS introducing a price on CO_2.

3.6.2 CO_2 implications of demand for gas for power generation

Outcomes in New Zealand's power generation sector are likely to be much more sensitive to CO_2 prices. For this 2016 study, significant new modelling was undertaken of the potential implications of CO_2 prices being higher than they have been to date – including an IEA-derived scenario of very high CO_2 prices. This analysis is detailed in section 5, but the high level conclusions are:

- There may be some opportunity to substitute gas for coal-fired generation as a result of higher CO_2 prices, including through high CO_2 prices resulting in the retirement of the remaining two Huntly Rankine coal-fired units.
- However, this effect of coal→ gas switching is likely to be significantly more than offset by substitution away from fossil generation generally (coal and gas) towards renewables as a result of higher CO_2 prices.

Thus, on balance, higher CO_2 prices will likely result in lower gas demand for power generation. However, there are likely to be economic limits to the extent of this substitution by renewables. These limits are driven by the economics of 'spilling' renewable generation at times when supply is greater than demand – noting that a large proportion of thermal generation output is providing low capacity factor duties such as dry-year, seasonal and within-day peaking generation.

3.6.3 CO_2 implications on petrochemical demand

The main impact of an increased price of CO_2 *in New Zealand* on petrochemical demand would be if it were introduced in such a way that handicapped petrochemical production in New Zealand relative to other jurisdictions which didn't impose a CO_2 cost on petrochemical production. However, as with industrial process heat demand detailed above, if the current NZ ETS approach of shielding Emission-Intensive Trade Exposed businesses were to continue, higher New Zealand CO_2 prices shouldn't impact materially on New Zealand petrochemical production.

More generally, as mentioned above, higher *international* CO_2 prices would likely to result in increased international gas demand over the next 10-20 years as they encourage switching away from coal to gas-fired power generation (and also – to the extent that higher international CO_2 prices apply to the production of petrochemicals[40] – switching from coal-based to gas-based petrochemical production). This higher international gas demand should generally increase international gas prices. That in turn will tend to improve the relative economics of petrochemical production in New Zealand versus overseas locations for gas-based petrochemical production, which will also tend to encourage local upstream activity.

3.6.4 Broader CO_2 implications on upstream exploration

Stronger international demand for gas induced by rising CO_2 prices, and the associated coal to gas power generation substitution dynamic, is expected to be positive for upstream activity at the international level. In particular, there is likely to be an increasing trade in LNG to meet strongly rising demand in Asia.

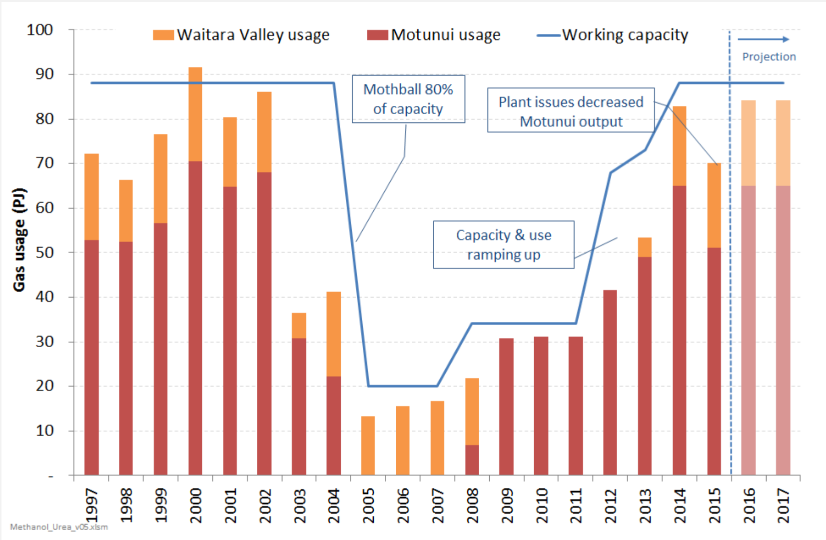
While New Zealand is not in the 'front row' for LNG developments, this favourable backdrop is expected to be supportive for New Zealand upstream activity, especially for frontier basins such as the Great South Basin, where exploration effort is explicitly targeting potential gas discoveries of a scale large enough to support LNG development.

[40] In many places around the world petrochemical producers are effectively exempt from CO_2 prices, even if such prices apply to power generation. The policy rationale for such exemptions is generally because petrochemicals are internationally traded (and thus can face distortions from different CO_2 prices applying in different jurisdictions), whereas power generation is generally not.

4 Gas demand for petrochemical production

Chapter summary

The bulk of methanol produced in New Zealand is exported, mainly to customers in north Asia. Given this export focus, the level of gas demand for methanol production is primarily driven by the competitiveness of the New Zealand plants, relative to other international methanol sources. Furthermore, gas makes up a substantial portion of the variable cost of production for methanol plants.



Methanex's large size and role as marginal buyer means that it has effectively operated as the major 'balancer' in the New Zealand gas market. When the gas supply outlook tightens and gas prices rise, it reduced production, and vice versa.

From a technical perspective, Methanex's existing New Zealand plants are likely to be capable of operating well into the future, barring any catastrophic failure (such as major fire). This reflects the nature of the processing plants, in which components are replaced when they wear out or become obsolete. This view is supported by Methanex's public position, such as its statement in 2014 that the New Zealand "*plants [are] good for another 20 years*".[41]

The key underlying point is that provided gas is available at competitive prices, the petrochemical plants are expected to provide a substantial source of demand for the foreseeable future. An indication of possible future intentions may emerge in the next 12 months, when planning decisions for 2017-2018 plant turnarounds are expected to be made.

Ballance Agri-Nutrients (Ballance) operates an ammonia urea plant at Kapuni in Taranaki that uses around 7 PJ of gas per year to produce 260,000 tonnes of urea fertiliser. Ballance has indicated that it has a gas supply contract that runs to 2020.[42]

New Zealand has significant local demand for urea, and currently imports approximately two thirds of its requirements. International freight costs are estimated to be around 10-15% of the delivered price in New Zealand.

The demand scenarios for petrochemical manufacturing projections are based on the following core scenarios:

- Scarce – representing a future where no major new supply sources are developed, and future development is largely around firming up incremental gas supply from existing fields. This is more likely in a scenario of sustained low future oil prices. In this scenario it is likely that gas for methanol production will continue at around current levels and then significantly scale back once New Zealand's reserves-to-production (excluding petrochemical demand) ratio declines below a certain 'threshold' point. The exact point at which this will occur is subject to significant inherent uncertainty, driven by factors such as international methanol and oil prices, and non-

41 Presentation to New Zealand Petroleum Summit, 2014.

42 See www.ballance.co.nz/news/winter+2012/kapuni+future+secure

petrochemical demand for gas. However, based on the observed contraction of methanol production in the early 2000's it is likely that a similar point could be reached between 2019 and 2022 absent the discovery and development of a significant new supply source in the next 5-8 years. Our 'Scarce' projection has the three methanol trains progressively moving to a mothballed state between 2019 and 2022.

- Plentiful – representing a future where gas exploration and development brings forward significant new supply from existing and/or new fields. This is more likely in a scenario of sustained high future oil prices, which generally encourage active upstream exploration and development. In this scenario, methanol production remains at full output for the duration of the projection.
- Central – representing a situation between these two extremes. Our central projection for petrochemical demand is simply an average of the plentiful and scarce scenarios. However, in reality, methanol demand may be more binary, being at either very high or very low levels, depending on the extent of forward reserves cover.

In all three scenarios, urea production remains stable, reflecting the fact that the significant local market for urea gives it a significant avoided shipping freight advantage compared with methanol production (whose output is predominantly sold in Asia).

4.1 Purpose

This chapter considers the likely future levels of gas demand from the petrochemical sector. There are two main sources of such demand:

- Methanol production at Methanex's two production plants at Motunui and Waitara Valley.
- Ammonia / Urea production at Ballance's Kapuni production plant.

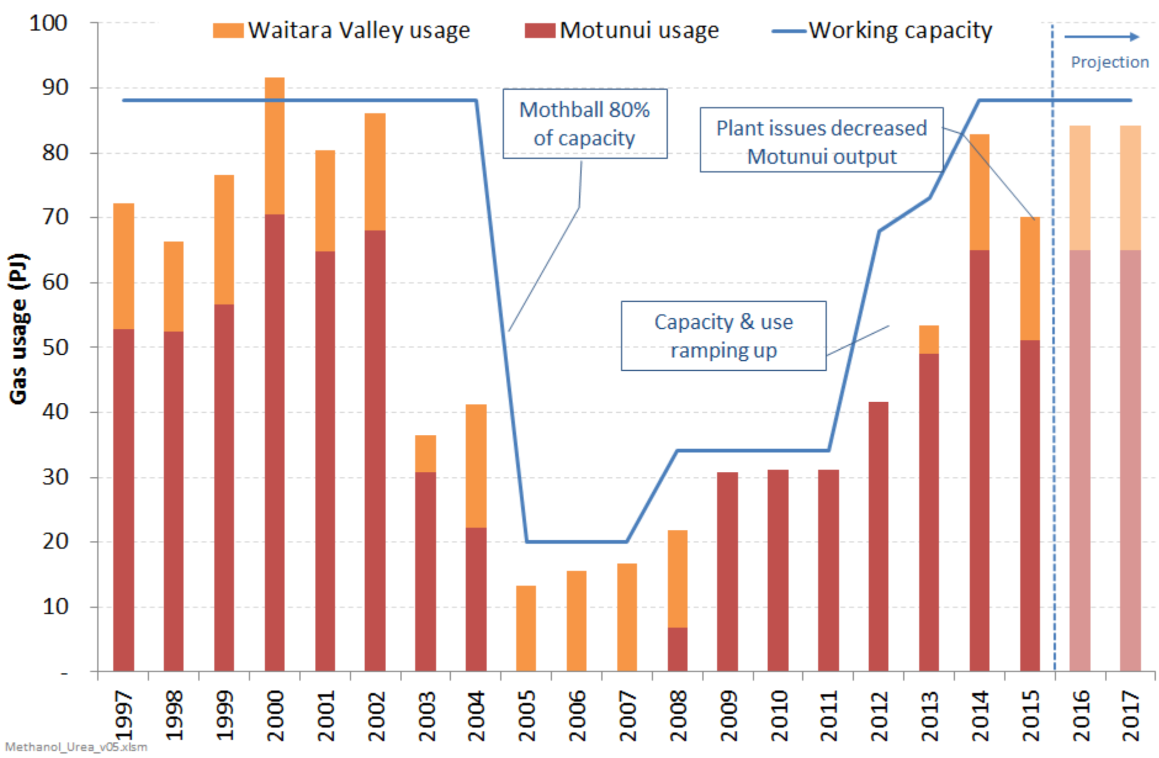
Each of these is considered in turn.

4.2 Methanol

The Motunui facility comprises two methanol trains, each capable of producing around 950,000 tonnes of methanol per annum and requiring approximately 35 PJ of gas to do so.[43] The Waitara Valley facility is a single, 530,000 tonne per annum train that requires around 20 PJ of gas when operating at capacity. Methanex's demand for gas has varied between around 15 PJ and 90 PJ per year since 1997, as shown in Figure 24.

[43] The amount of gas required to produce a tonne of methanol varies according to the CO_2 content in the gas. Gas with higher CO_2 content can produce a greater quantity of methanol. Different gas fields have different levels of CO_2 content.

Figure 24: Methanex gas use and working capacity since 1997



Source: Concept analysis of company reports and pipeline data

The bulk of methanol produced in New Zealand is exported, mainly to customers in north Asia. Given this export focus, the level of gas demand for methanol production is primarily driven by the competitiveness of the New Zealand plants, relative to other international methanol sources. Furthermore, gas makes up a substantial portion of the variable cost of production for methanol plants.

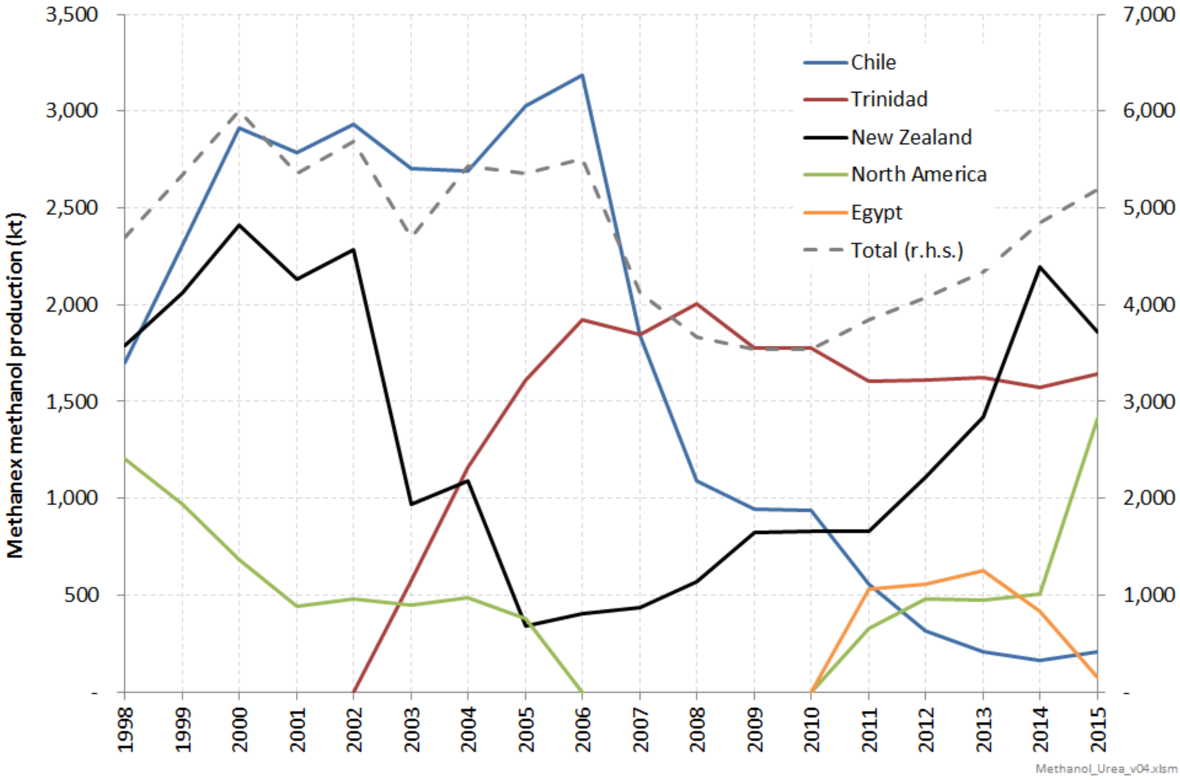
These factors explain:

- The significant fall in gas demand for methanol production from 2002, as New Zealand gas prices rose due to a tightening supply outlook.
- The recovery in gas demand for methanol production since 2011, reflecting the improved New Zealand gas supply outlook and (consequently) more competitive gas input costs.

Methanex's large size and role as marginal buyer means that it has effectively operated as the major 'balancer' in the New Zealand gas market. When the gas supply outlook tightens and gas prices rise, it reduced production, and vice versa. For the reasons discussed in the next section, we expect this role to continue into the future.

This changing pattern of reserve positions and gas prices in other countries around the world, likely also explains the changing pattern of Methanex's international production as shown by Figure 25.

Figure 25: Methanex's international methanol production



Thus, if a region's gas position gets relatively tight (as in the United States from the late 1990s to mid-2000's and Chile from the mid-2000s), methanol production has substantially scaled back, but if a region starts to enjoy a situation of relative surplus, methanol production starts to expand (as in the United States more recently).

4.2.1 Gas demand outlook for methanol production

From a technical perspective, Methanex's existing New Zealand plants are likely to be capable of operating well into the future, barring any catastrophic failure (such as major fire). This reflects the nature of the processing plants, in which components are replaced when they wear out or become obsolete. This view is supported by Methanex's public position, such as its statement in 2014 that the New Zealand "*plants [are] good for another 20 years*".[44]

The major operational decision points for the plants are likely to be around the periodic turnarounds, when major maintenance and inspections occur and catalysts are replaced. At these points, there are lumpy expenditure commitments to maintain the plants in operation. Historic data indicates that turnarounds for the New Zealand plants occur at approximately 4-5 year intervals, with the next turnarounds likely to be around 2017-2018 for the Waitara Valley plant and one of the Motunui trains.

Methanex's public statements also provide some indication of its future operating intentions. In 2012, Methanex announced a 10-year gas purchase contract for sizeable volumes with Todd Energy, and five-year contract with an undisclosed party for gas supply to Motunui. These contracts suggest an intention to operate at least one unit until 2022. The gas contract durations also appear to match relatively closely with the inferred turnaround schedule.

Although Methanex purchases some gas on a spot basis, most of its gas purchases are understood to be on term contracts.[45] On the assumption that this pattern will continue, Methanex is likely to be

[44] Presentation to New Zealand Petroleum Summit, 2014.

[45] Methanex was a founding supporter for the gas spot market hosted by emsTradepoint, however volumes traded through this platform are still relatively small compared to Methanex's demand.

considering gas re-contracting decisions in the next 12-24 months (noting contracts are typically finalised in advance of supply commencement).

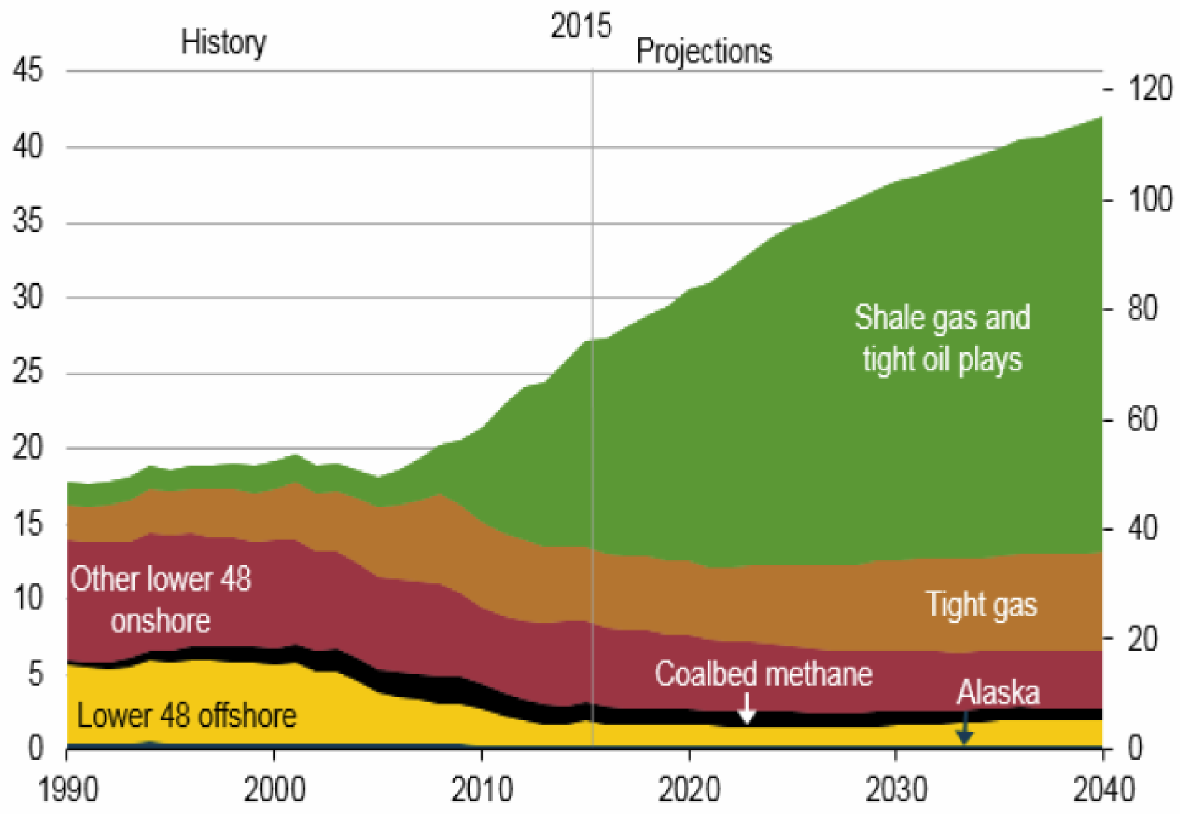
We expect the re-contracting decisions to be shaped by a number of key factors:

- Methanex's cost of producing methanol in New Zealand – compared to other locations where it can produce or acquire methanol.
- the willingness of New Zealand gas producers to supply gas at prices which would enable the New Zealand methanol plants to be internationally competitive.

As we have stated previously,[46] Methanex's most likely alternative production source is North America. This view is supported by its decision to relocate some of Chilean plants to Giesmar in Louisiana, and to restart Canadian capacity. Other methanol producers have also restarted, or announced intentions to expand their methanol production capacity in North America. The fundamental reason for this resurgence of North American methanol manufacturing is the growth in shale gas production in that region and the consequent low North American gas prices.

Figure 26 shows a recent projection released by the United States Energy Information Administration (EIA). It projects that ongoing growth in shale gas production will more than offset declining conventional sources, and will shortly move the United States into a net gas exporter position. The EIA expects this growth to be supported by further technology improvements, enabling higher recovery rates at lower costs.

Figure 26: United States gas production (dry gas in tcf/year)



Source: United States Energy Information Administration, Annual Energy Outlook 2016 Early Release, May 2016

[46] See, Concept Consulting Group Ltd, *Long term gas supply and demand scenarios*, prepared for Gas Industry Company, September 2014, p 51.

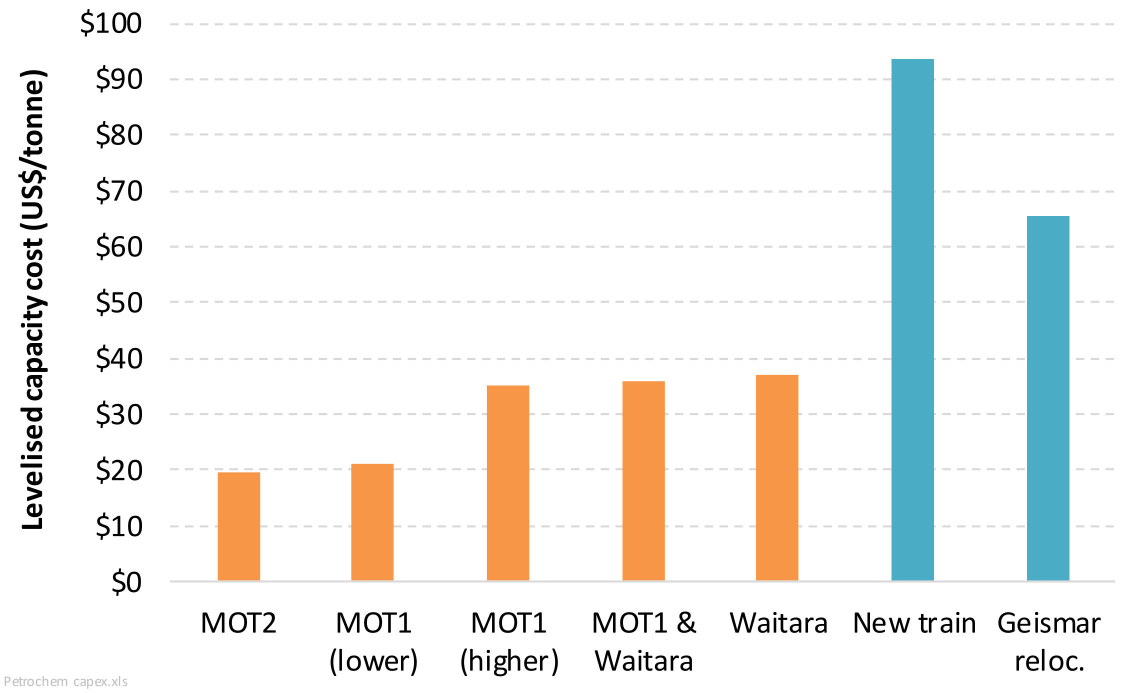
In terms of future United States gas prices, the EIA projects a lift from recent low levels (around US$2.6/mmBtu in 2015[47]) to "above US$4.4/mmBtu by 2020"[48] (equivalent to approximately NZ$6.4/GJ).[49] The CME forward curve also indicates an expectation of recovering United States gas prices, although the rate of increase is somewhat lower, with prices rising to around US$3/mmBtu by 2020 and to US$3.5/mmBtu by 2022[50] (equivalent to approximately NZ$4.4 - NZ$5.1/GJ).

In addition to headline gas prices, other factors will affect the competitiveness of the Taranaki plants compared to North American capacity. These include:

- Capital costs – the Taranaki plants are expected to have a cost advantage compared with decisions to build new plants, or relocate further capacity to North America. This is illustrated by Figure 27 which shows the estimated costs of maintaining capacity in New Zealand, compared to new or relocated plant in North America. This factor is estimated to provide the New Zealand plants with a cost advantage over North American plant of around $2 to $2.5/GJ (new build), or $1 to $1.5/GJ (relocated plant - which is arguably the more relevant measure in the near term).[51] This advantage would not apply for competition against existing North American plants. However, given that further growth in methanol demand is expected, further capacity additions or relocations are likely in the medium term.[52]
- Shipping costs – while detailed information on costs is not available, in terms of sea distance, the New Zealand plants are considerably closer to north Asian markets than their United States Gulf Coast counterparts. However, if significant methanol volumes were to be shipped from the Pacific Coast (not currently the case), this advantage would be negated.

47 Average spot price at Henry Hub in 2015. This is reported to be the lowest annual average price since 1995.
48 US EIA, Annual Energy Outlook 2016, Early Release, p.50, May 2016.
49 Based on the implied forward exchange rate of 0.647 USD/NZD and converted to NZ$/GJ.
50 Based on prices for Henry Hub gas futures contracts, quoted on CME in mid-May 2016.
51 These estimates assume a lower discount rate for North American investment, and a higher methanol yield per unit of gas used.
52 Methanex states that demand has grown at 7% CAGR in 2006-2015, and reports that the same level of growth is projected for 2016-2019, see p.7, *Methanex Corporation,* Methanex Investor Presentation, May 2016.

Figure 27: Methanol plant capacity costs (estimated)



Source: Concept analysis of Methanex disclosures – varying cost figures have been disclosed for MOT1 at different times.

These factors imply that the existing methanol production capacity in New Zealand would have the *ability to pay* up to around NZ$5.5-8/GJ and remain competitive against relocated plant in the US.[53] However, methanol plant owners will presumably seek lower gas prices if these can be achieved, to provide a return on sunk investment in New Zealand plant. If Methanex's marginal source of production is an existing overseas plant, its *willingness to pay* for gas in New Zealand will be lower than if its marginal source of production were a re-located plant. In such circumstances, its willingness to pay will be driven by the alternative international gas cost (likely US Gulf Coast gas) factored by any shipping differential to take the methanol to the end market.

For the present purposes, the key observation is that even with an outlook of relatively low gas prices in the US, the New Zealand methanol plants are likely to be competitive, provided New Zealand has sufficient gas inventory.

However, there has been little exploration success in New Zealand over the last couple of years, and with current low oil prices there is little or no material ongoing exploration effort which is targeting potential new gas finds.

Accordingly, if the current levels of petrochemical demand were to continue then, New Zealand's reserves-to-production ratio, *based on current P50 reserves*, is projected to fall to approximately 7years by 1 January 2020, and 5 years by 1 January 2022. This is expected to put upward pressure on gas prices.

It appears that all three of Methanex's methanol production trains are coming up for major plant turn-arounds in 2017/18, when decisions will be required on their operation over the subsequent 4-5 years.

Whether Methanex will re-contract gas supply to maintain their current high levels of demand will be influenced by gas producers' incentives. The gas price in any such contract is likely to reflect Methanex's opportunity cost of producing methanol at one of its overseas locations. This price for sale to Methanex is likely to be lower than the level which would prevail generally in a tighter New Zealand gas market.

---

[53] Based on the Henry Hub futures contract estimate of NZ$4.4/GJ, plus the capex advantage of NZ$1/GJ, or alternatively the EIA price estimate of NZ$6.4/GJ plus a capex advantage of NZ$1.5/GJ.

However, gas producers may be willing to accept such a price, if the alternative is to keep the gas in the ground and postpone sales for a significant period of time. In this respect, although the 1 January 2017 reserves-to-production ratio is projected to be 9 years based on current levels of demand, it would be around 18 years based on non-petrochemical demand (and 26 years if baseload gas-fired generation (the next most price-sensitive demand sector) is also excluded).

Thus, gas revenue 'now' may well be more valuable than gas revenue a decade or more hence, even if such future gas prices are materially higher. Plus, to the extent that keeping gas in the ground also postpones associated oil sales (albeit possibly at higher future prices) and extends the field life (and associated operating costs), the incentive on producers to make discretionary gas sales earlier at a lower price may be even greater.

At some point, local market gas prices will rise to a level where producers prefer to not sell gas at a relatively lower price for methanol production, and instead conserve resources for future gas sales to higher value local users. The exact time when such a cross-over point will occur will depend on a number of factors including:

- international gas prices (which influence Methanex's willingness-to-pay);
- oil prices (which comprise a significant additional part of a field's revenue stream);
- the dynamics of the New Zealand power generation market – being the other major 'discretionary' demand sector that would likely reduce gas demand in response to a tightening gas market; and
- the extent to which additional gas supply will be brought forward to the market.

This last point is particularly significant as, although there is currently little prospect of *new* fields being discovered and brought to market within the next 5-7 years given the lack of current exploration, New Zealand has a significant quantity of contingent resources within *existing* fields. These contingent resources are regarded as being uneconomic to develop at present. As at 1 January 2016, the reported 2C resources were 1,700 PJ, in comparison to the reported 2P reserves of 2,060 PJ.

If the New Zealand gas market tightens and gas prices rise, it is therefore likely that a proportion of contingent resources will become economic to develop – and will be reclassified as reserves.

Thus, maintaining high levels of gas demand for methanol production is likely to bring forward the time when contingent resources will become economic to develop, and be reclassified as reserves.

Further, higher gas prices would also likely bring forward the time when upstream producers resume significant exploration in New Zealand – noting that the prospectivity for additional gas in the Taranaki basin is still considered positive.

Given these dynamics, it is unlikely that the very low reserves-to-production ratios projected above based on *current* P50 reserves would eventuate in practice.

At some later point, absent major new gas sources being identified, New Zealand's reserves could drop to a point where gas producers prefer to not to sell to Methanex. Evaluation of when such a position may emerge is subject to significant inherent uncertainty given the factors outlined above. However, if history is a guide to when such outcomes may occur, it may be instructive to note that Methanex rapidly reduced demand in the early 2000's once the P50-reserves-to-production ratio reached 6 years. Our projections indicate that, absent a major new gas discovery and/or the development of some of the gas currently classed as contingent, New Zealand would reach that point in 2022 based on current levels of petrochemical demand and assuming some price response from the power generation sector.[54]

Therefore, it is potentially the case that we could continue to see relatively high petrochemical demand until approximately 2022, followed by a rapid scaling-back of methanol demand – potentially to close to

[54] If the Tiwai smelter were to retire in 2018/19, the associated reduction in gas-fired power generation would push out the point where New Zealand's reserves-to-production ratio reached this cross-over point by a couple of years.

zero – from that point on. Were such an outcome to occur, it is unlikely that the methanol plants would be permanently retired, but rather put into mothballs to enable a resumption of production if and when a significant new gas field were developed in the future. Such a strategy proved to be valuable for both Methanex and New Zealand's gas sector in the 2000's – i.e. Methanex is considered a key enabler for New Zealand's oil and gas sector.

As regards the potential for significant *new* methanol production capacity in New Zealand, this would be dependent on a very large new find being discovered whose size is such that it would not be consumed by New Zealand's existing gas consumers (including the existing three methanol trains) within the next 15 to 20 years. i.e. of the order of 3-5,000+ PJ.

If such a find was discovered, the main options for developing new demand to commercialise the gas would be Methanol, Urea, or LNG. Given that such a situation would be unlikely to emerge for at least 5 to 10 years, it is hard to speculate as to which option (or combination of options) would be most economic.

Over time, the netbacks from monetising 'stranded' gas from developing any of these three commodities would be expected to be roughly equivalent, but at a specific moment in time and location there are likely to be variations between the commodities depending on factors such as the extent to which each commodity:

- is in a situation of relative global production over- or under-capacity;
- has regional dynamics relating to demand and competing marginal international sources of supply (noting that shipping cost differentials can materially impact on the relative economics of producing these commodities).

It is possible that at some time in the future that expanded methanol may be the best of the three options to monetise a significant new gas find. However, the gas price would need to be quite low to support a new methanol processing facility, and provide assured supply for a considerable period (15+ years), and thus be competitive with expanded methanol production elsewhere in the world. For example, Methanex has indicated in the past that it would look for a gas price of around US$2/mmBtu (around NZ$2.85/GJ at an exchange rate of 0.7 USS/NZ$) to support a new plant.[55]

4.3 Gas demand for ammonia urea production – history and outlook

Ballance Agri-Nutrients (Ballance) operates an ammonia urea plant at Kapuni in Taranaki that uses around 7 PJ of gas per year to produce 260,000 tonnes of urea fertiliser. Ballance has indicated that it has a gas supply contract that runs to 2020.[56]

New Zealand has significant local demand for urea, and currently imports approximately two thirds of its requirements. International freight costs are estimated to be around 10-15% of the delivered price in New Zealand. Domestic production avoids this freight cost, and this advantage equates to a gas-equivalent cost of ≈ NZ$2/GJ – NZ$2.5/GJ for North Island deliveries.[57] This freight advantage is not as great for the South Island, and is estimated to be around $0.70/GJ in equivalent terms, because of domestic shipping costs.

Ballance has secured resource consents to run the Kapuni plant to 2035, and recently announced plans to expand efficiency and production capacity at the plant. The chief executive indicated that the expansion would require significant capital, and that the firm was seeking a development partner.

55 Methanex CEO statement in May 2012, referring to the price needed to support investment at new production locations.

56 See www.ballance.co.nz/news/winter+2012/kapuni+future+secure

57 Depending on the gas to urea conversion efficiency of the plant, and forward rate.

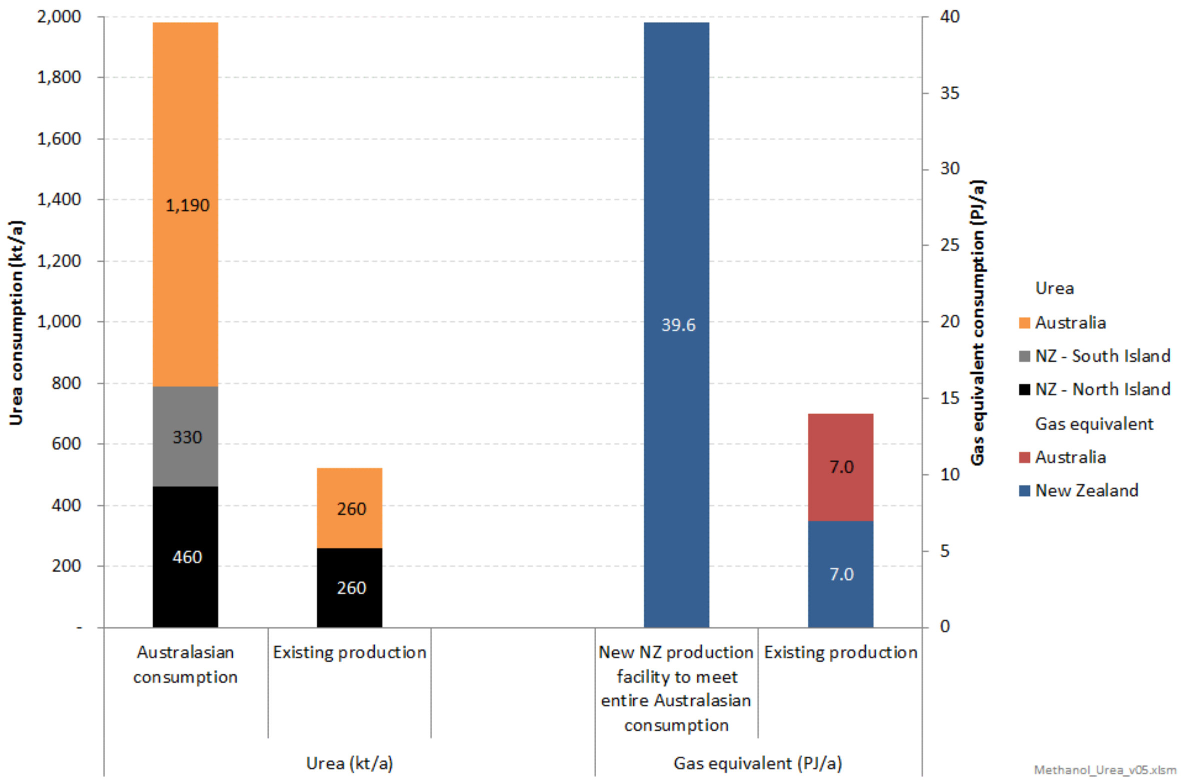
Media reporting suggested that the expansion would cost around US$500 million, and lift gas use by approximately 2 PJ per annum.[58]

It is unclear how much additional production capacity this would create, but it could be significant (perhaps 30% or more).[59] If expansion of this magnitude did occur, the upgraded plant would provide approximately 75% of North Island urea requirements. Given the freight advantages enjoyed by the Kapuni plant, it appears relatively likely that this expansion will proceed, and would lift future gas demand to around 9 PJ per annum.

However, Ballance has recently announced the partner with whom it was seeking to develop the expansion has pulled out, and thus the expansion is unlikely to happen "in the near future". In the announcement they indicated they were "…continuing to talk with other potential partners for a future rebuild", but if they were unable to secure a partnership agreement this time around, the project will be put on hold for revisiting at a future date.[60]

The prospects of further expansion are less clear. They would likely depend on sales of urea into the South Island and/or the Australian market. In volume terms, these market segments utilise around 1.5 million tonnes of urea per annum, and are shown in Figure 28. If this demand were met by New Zealand production, it would equate to additional gas demand of around 30 PJ per year, assuming the conversion efficiency for a modern plant.

Figure 28: Estimated demand for urea in Australia and New Zealand



Source: Concept analysis

58 Media report on 3 March 2016.

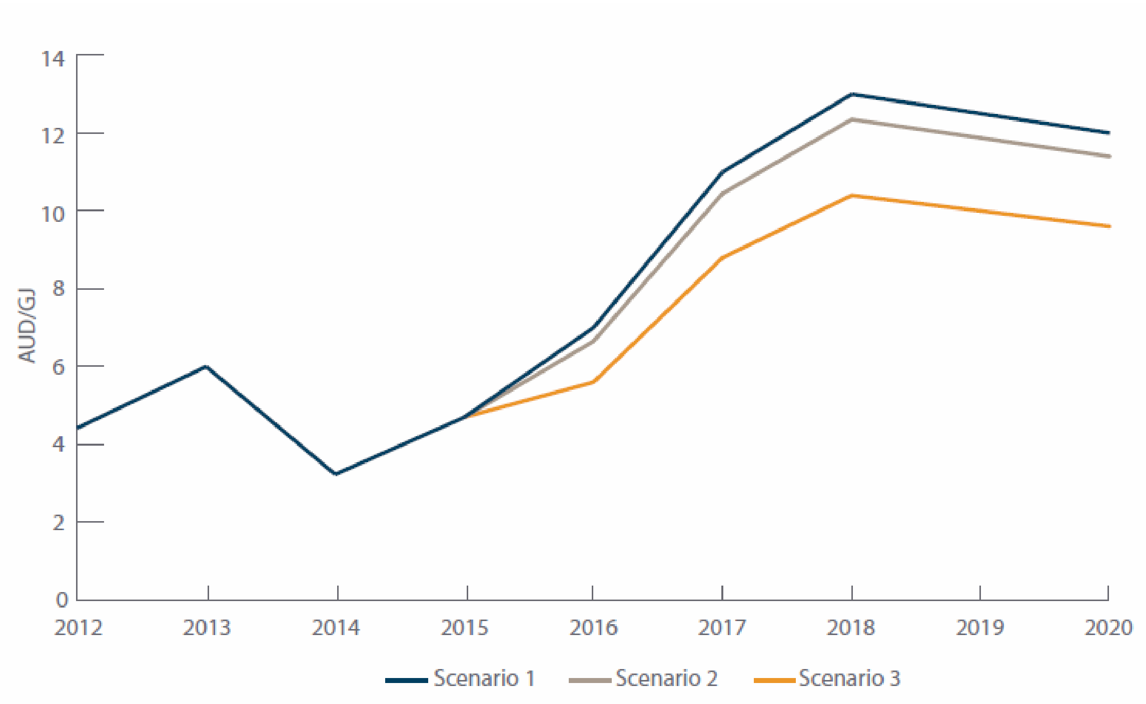
59 The existing plant produces approximately 37,000 tonnes of urea per PJ of gas, compared to reported yields of around 50,000 tonnes per PJ for modern plants. Assuming a level of efficiency that is intermediate between these levels and the reported increase in gas use to 9 PJ per year, this implies output of around 380,000 tonnes per annum.

60 http://www.ballance.co.nz/Our-CoOp/Our-Community/News/2016/Winter/Kapuni-upgrade-scoping-costs-written-off

At present these markets are served by a mix of imports and production from one Australian plant located near Brisbane. Urea manufacturing in Australia is coming under intense pressure as gas prices in the east coast gas market move toward levels determined by LNG netback values.

Figure 29 shows recent and projected gas prices in Queensland for a range of market scenarios. Even under the lower cases, prices are projected to almost double to A$8/GJ or more within 2 years.

Figure 29: Projected gas prices - Queensland



Source: ANZ Research, AEMO

While the Queensland plant has largely been insulated from these price pressures to date, its major term gas contracts come to an end in 2017. The plant owners recently booked a write-off on the plant value of over A$100m, and a decision on the plant's future may be made within the next 12-18 months.

If the plant were to close, this would increase the reliance on imported urea to meet Australian and remaining New Zealand (mainly South Island) demand. A New Zealand plant serving these segments would have some freight advantage relative to supplies from the Middle East. This is estimated to be around NZ$0.7/GJ in gas equivalent terms – considerably lower than the advantage for serving North Island demand from the existing Kapuni plant.

Given current economics, it appears likely that the Australian urea plant will shut down within the next few years. However, it is much less certain whether this would present an opportunity to further expand New Zealand production. On balance, it appears that the additional demand may be met from imports into Australia from the Middle East, given that the freight advantage for a New Zealand urea producer is relatively limited.

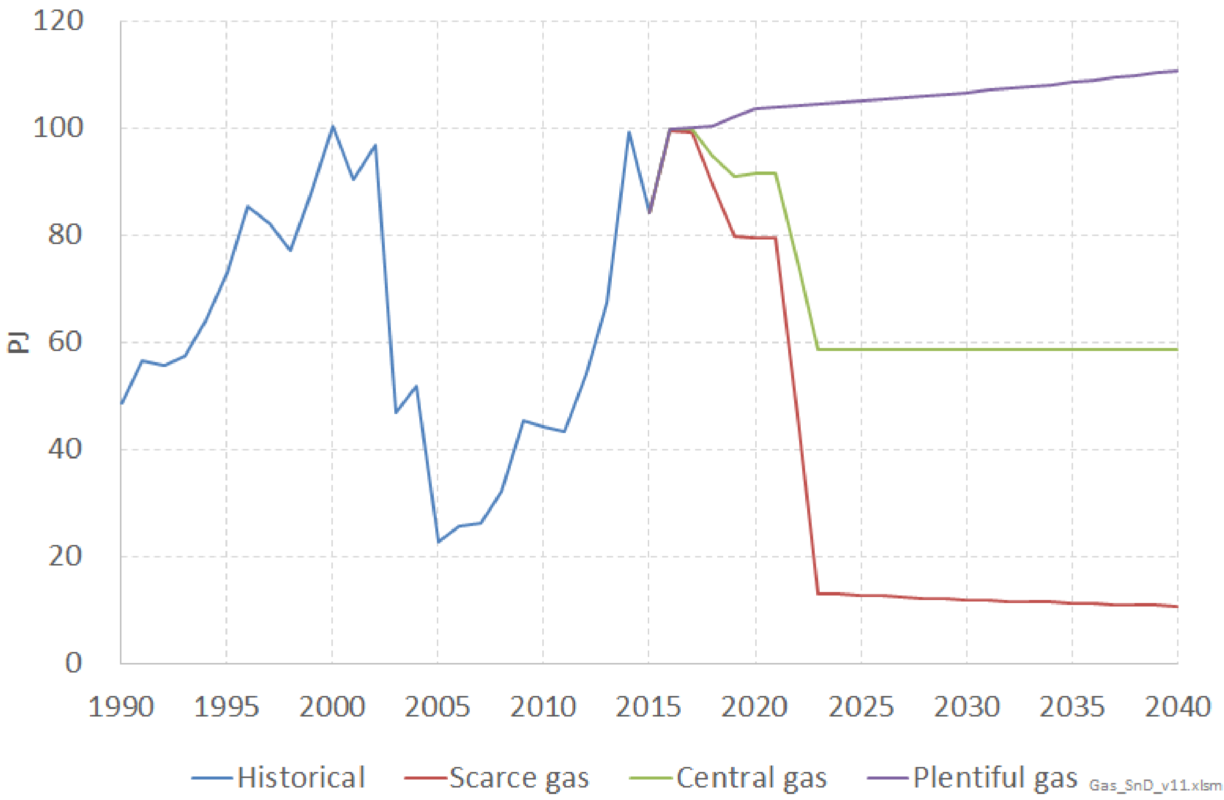
4.4 Petrochemical gas demand projections – summary

Figure 30 shows our sectoral gas demand scenarios for petrochemical manufacturing which takes account of the factors discussed above. More specifically, the projections are based on the following core scenarios:

- Scarce – representing a future where no major new supply sources are developed, and future development is largely around firming up incremental gas supply from existing fields. This is more likely in a scenario of sustained low future oil prices. In this scenario it is likely that gas for methanol production will continue at around current levels and then significantly scale back once New Zealand's reserves-to-non-petrochemical-demand cover ratio declines below a certain 'threshold' point. The exact point at which this will occur is subject to significant inherent uncertainty, driven by factors such as international methanol and oil prices, and non-petrochemical demand for gas. However, based on observation on historical contraction of methanol production in the early 2000's it is likely that a similar point could be reached between 2019 and 2022 absent the discovery and development of a significant new field in the next 5-8 years and/or the development of some of the significant quantity of gas accumulations currently classed as contingent resources. Our 'Scarce' projection has the three methanol trains progressively moving to a mothballed state between 2019 and 2022.

- Plentiful – representing a future where gas exploration and development brings forward significant new supply from existing and/or new fields. This is more likely in a scenario of sustained high future oil prices, which generally encourage active upstream exploration and development. In this scenario, methanol production remains at full output for the duration of the projection.
- Central – representing a situation between these two extremes. Our central projection for petrochemical demand is simply an average of the plentiful and scarce scenarios. However, in reality, methanol demand may be more binary, being at either very high or very low levels, depending on the extent of forward reserves cover.

Figure 30: Gas demand scenarios – petrochemicals[61]



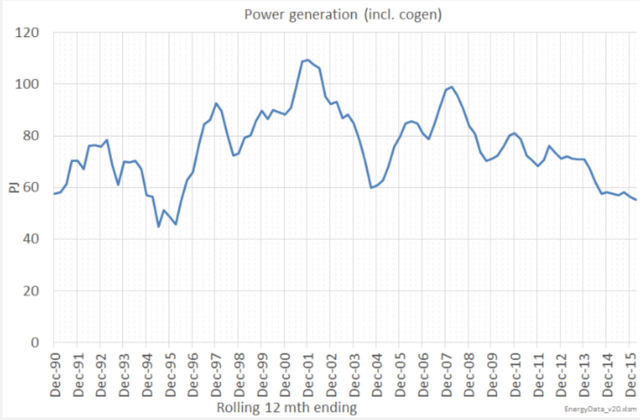
[61] The historical petrochemical gas demand excludes synfuel production in the early 1990s.

5 Gas demand for power generation

Chapter summary

A number of factors have driven the historical variation in demand for gas for power generation:

- Variations in renewable generation – i.e. year-to-year changes in the amount of hydro and (to a lesser extent) wind generation
- Changes in electricity demand
- Changes in the relative competitiveness between types of power stations
  - Between renewables and thermal
  - Between coal and gas
  - Between different types of gas-fired power station



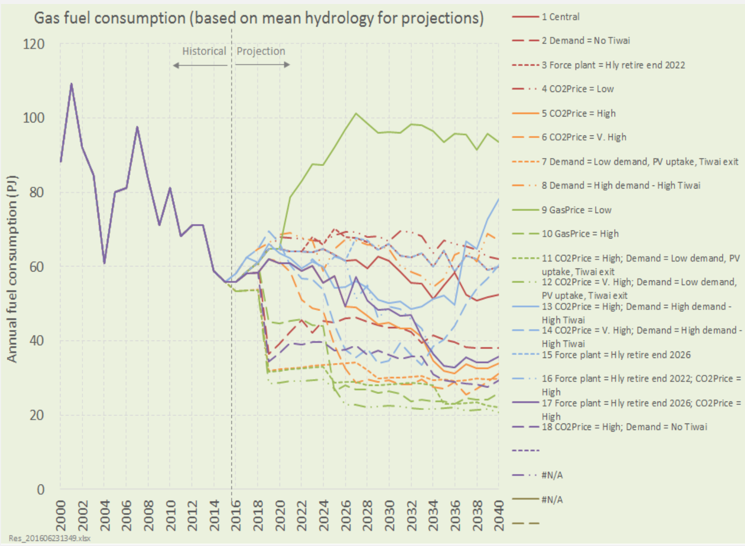
Each of these factors are likely to also drive future outcomes.

Battery storage is an option to avoid costs of providing infrequently-used generation and network capacity to meet the 1-2% of periods that currently make up the critical peak system demand.

It is expected that batteries will possibly reduce the need for peaking gas power generation. However, it is unlikely that batteries will be able to replace the role that gas power generation plants play for providing seasonal generation and dry/wet year hydro balancing.

Concept's suite of electricity and gas market models were used to examine possible futures for gas for the power generation sector. As well as seeking to project likely power station gas demand, the models were used to examine the sensitivity of outcomes to a number of key drivers:

- Demand – both the general rate of demand growth, as well as specific examination of a potential Tiwai exit from 2019[62]
- Potential retirement of the Huntly Rankine units, through simulating the <u>forced</u>[63] retirement of the remaining two units, once the existing contracts covering their output expire after 2022
- CO_2 prices – through examining a range of different CO_2 price scenarios



---

[62] This is a scenario assumption, as the smelter has the ability to exit at any time from 1 January 2018, provided it gives 12 months' notice.

[63] Whereas the model generally only retires thermal units endogenously (i.e. through undertaking an evaluation as to whether retirement of a unit would be least-cost given the specifics of the scenario (e.g. demand, fuel and CO_2 prices)), it is possible to exogenously force the retirement of a unit at a particularly date on a scenario basis – irrespective of whether the model determines whether this would be a least cost outcome.

- Coal vs gas economics – through examining scenarios with different gas prices (both the general level, and the cost of providing flexibility (or swing)).

5.1 Purpose

This chapter discusses gas demand for power generation, and sets out future demand projections under a range of scenarios.

5.2 Types of gas demand for power generation

In New Zealand, gas is used in four main types of power station.

- 'Rankine cycle' steam turbines – a boiler is used to raise steam to drive a turbine
- Combined-cycle gas turbines (CCGTs) – high-efficiency power stations using a combination of a gas turbine, plus a steam turbine driven using waste heat from the gas turbine.
- Open-cycle gas turbines (OCGTs) – Similar to a CCGT, but without the steam turbine at the back-end. Lower efficiency than a CCGT, but slightly higher than a steam turbine.
- Cogeneration – Waste heat from the electricity generating turbine is used to provide heat for an industrial process.

The main stations of these types are set out in Table 3 below.

Table 3: Main gas-fired power stations in New Zealand

Type	Name	Capacity (MW)	Built	Owner	Notes
Rankine	Huntly	2[64] x 250	1982 - 85	Genesis	Originally built as a coal-fired station, but with the discovery of the Maui gas field it was converted to be a 'dual-fuel' station which could additionally burn gas.
CCGT	TCC	385	1998	Contact	Located in Taranaki
	e3p	400	2007	Genesis	Also known as Huntly Unit 5.
	Otahuhu B	365	2000	Contact	Retired in September 2015
	Southdown	125	1996	MRP	Retired December 2015
OCGT	Huntly Unit 6	48	2004	Genesis	
	Stratford	2 x 100	2011	Contact	Located in Taranaki close to Contact's Ahuroa gas storage facility
	McKee	2 x 50	2012	Todd	Located in Taranaki next to the McKee-Mangahewa gas production facility
Cogen[65]	Te Rapa	44	1999	Contact	Provides steam to the Te Rapa dairy factory
	Whareroa	70	1996	Nova & Fonterra	Provides steam to Whareroa dairy factory

[64] The station was originally built as 4 x 250 MW units. However, Genesis has permanently retired two units in (2012 and 2014).

[65] There are other significant cogeneration plants in New Zealand. However, these are predominantly fuelled by biomass (in the case of those located in the wood processing sites) or process waste heat (in the case of the Glenbrook steel mill) and gas is only a relatively small input to the cogeneration unit.

	Kapuni	25	1998	Vector & Nova	Provides steam to the Kapuni dairy plant

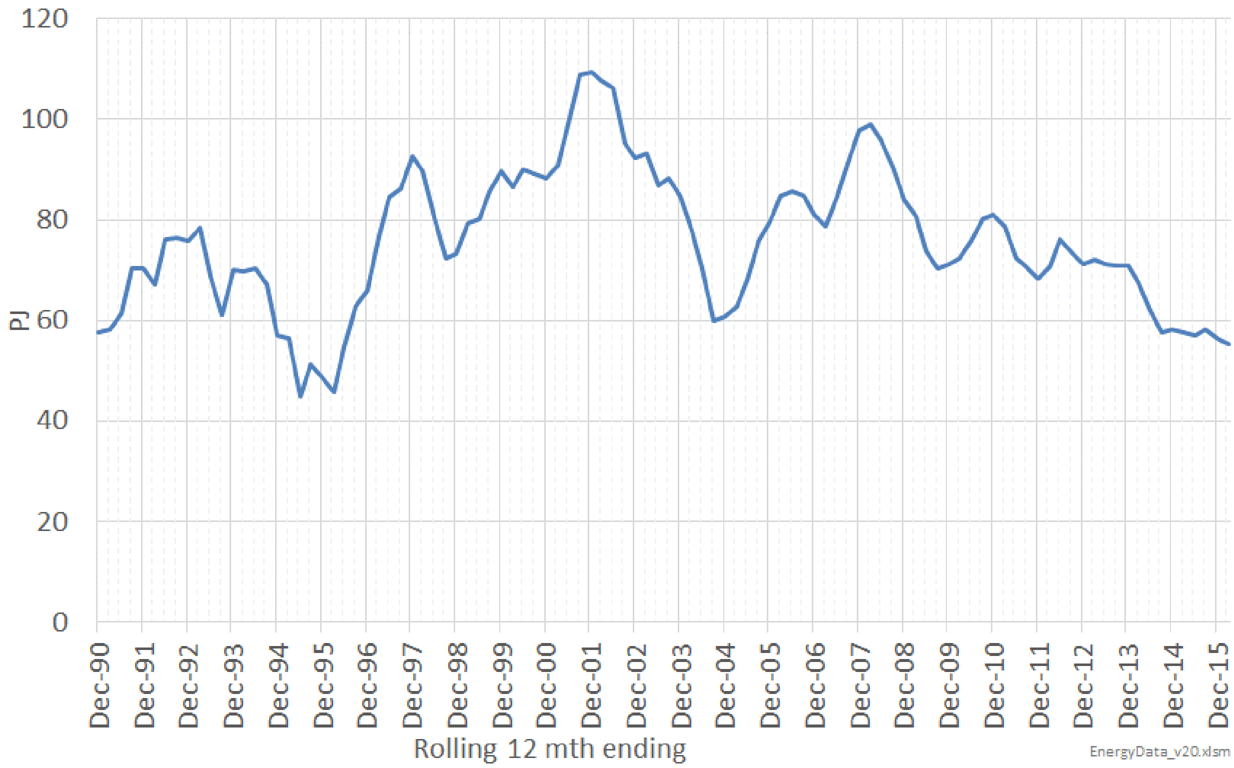
There are two other significant thermal plant of note in New Zealand:

- the 155 MW *diesel*-fired OCGT at Whirinaki in the Hawkes Bay, owned by Contact Energy.
- The 5 x 120 MW oil / gas –fired Rankine steam plant at New Plymouth. This plant was built in the mid-1970s, but was progressively retired, unit-by-unit, from the early 2000s to 2008. Its output is included in the historical data sets considered.

5.3 Historical drivers of gas demand for power generation

Figure 31 shows the historical change in gas demand for power generation in New Zealand.

Figure 31: Historical gas demand for power generation (including cogeneration)



A number of factors have driven these historical outcomes:

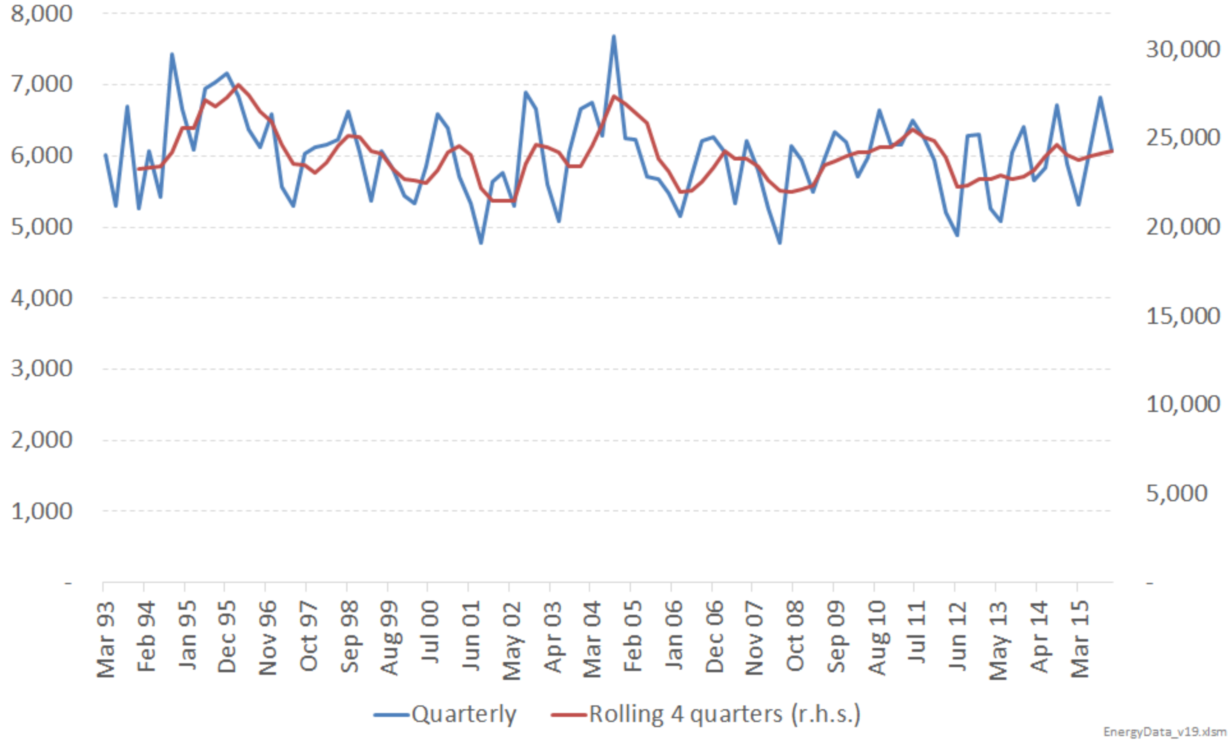
- Variations in renewable generation – i.e. year-to-year changes in the amount of hydro and (to a lesser extent) wind generation
- Changes in electricity demand
- Changes in the relative competitiveness between types of power stations
  - Between renewables and thermal
  - Between coal and gas
  - Between different types of gas-fired power station

Each of these factors are likely to also drive future outcomes. The rest of this sub-section explores these drivers.

5.3.1 Variation in renewable generation

In terms of variations in renewable generation, the most significant factor is the variation in hydro generation due to variation in inflows. This is illustrated in Figure 32.

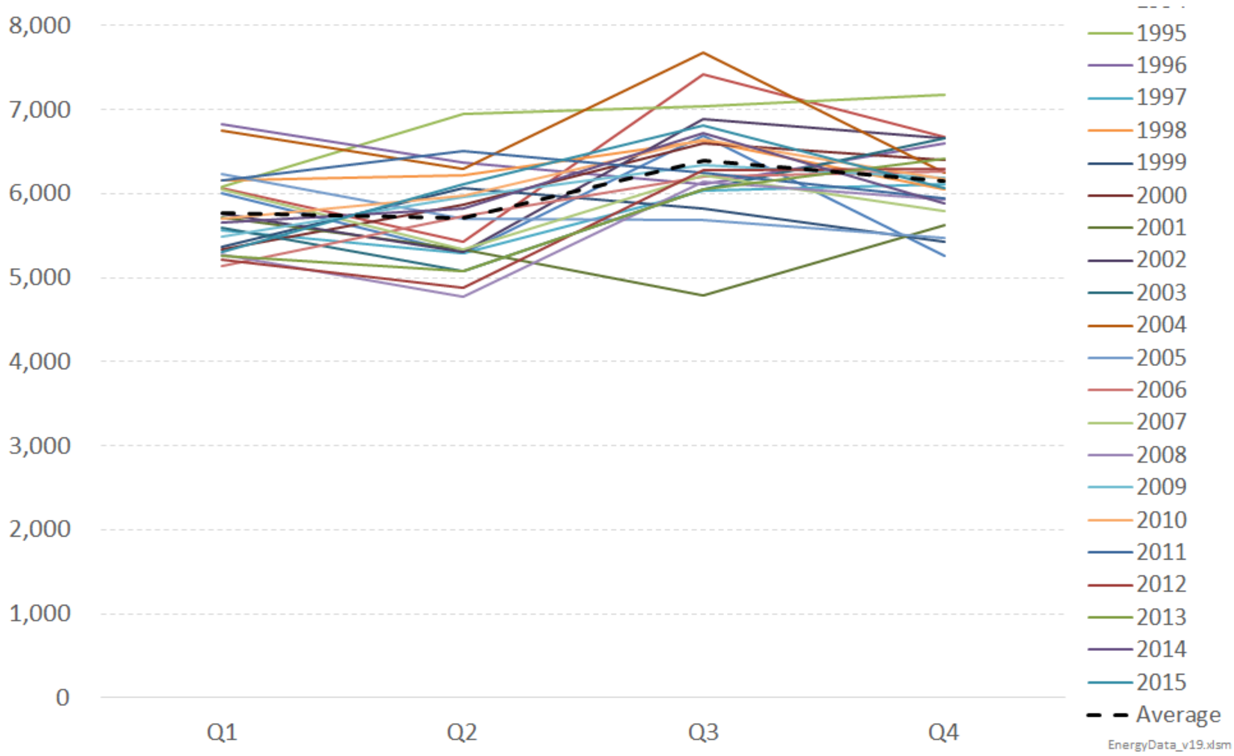
Figure 32: Historical variation in hydro generation (GWh)



On an annual basis, for the historical period in question, the difference between 5th and 95th percentile is approximately 5 TWh. As can also be seen, the proportional variance between high and low inflow periods is much greater on a quarterly than on an annual basis.

When considering historical inflows going back to 1932 (when records began), the variance is even greater. Figure 33 shows that this variation can occur throughout the year, although potentially with greater variation in the two winter quarters.

Figure 33: Historical quarterly hydro generation (GWh)



In addition to this hydro variation, there is also variation in wind generation. Analysis of historical wind and hydro inflow series indicates that there is some correlation between the two – i.e. dry years tend to be correlated with 'calm' years. This is due to both phenomena being driven by the same underlying weather systems. This will tend to exacerbate the hydro variation. However, at present, wind is only about 6% of total generation compared with approximately 58% for hydro. Plus, the variation in wind is not as great as the variation in hydro. Accordingly, the extent of wind exacerbation of hydro variation is material, but not huge.

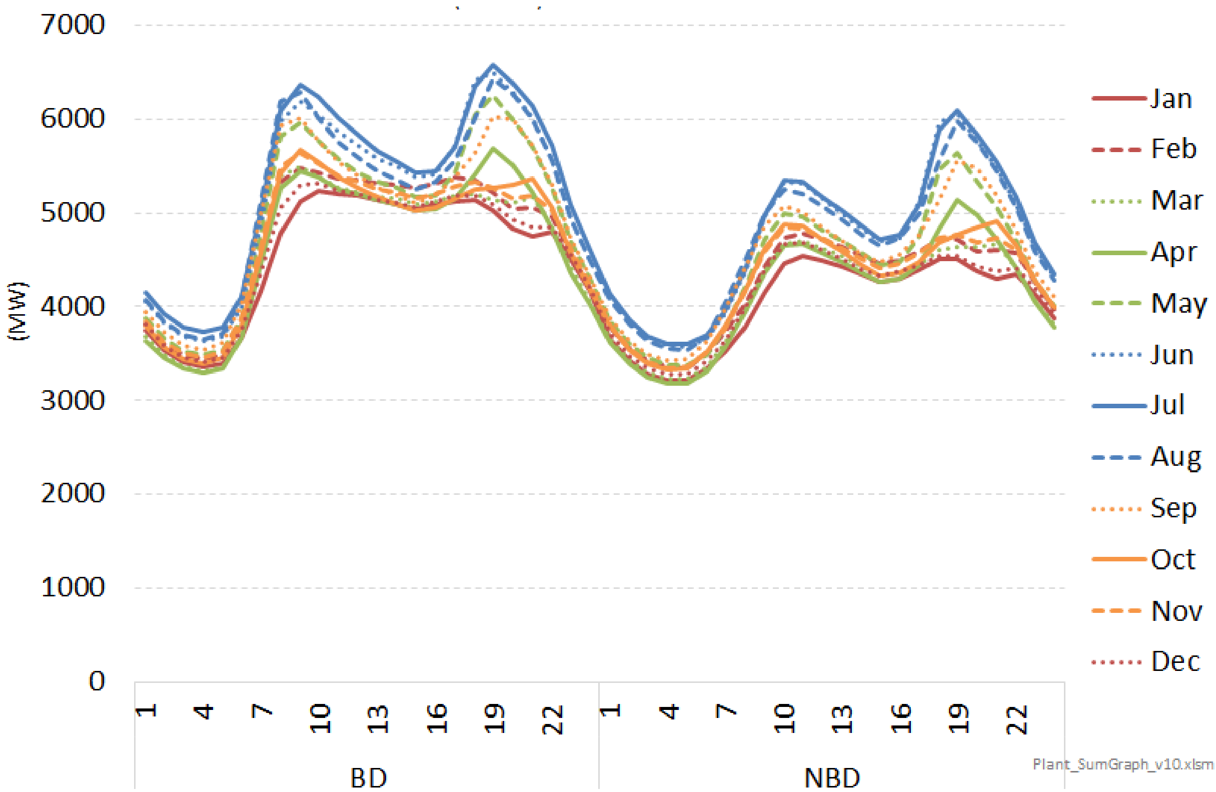
This variation in renewable generation is almost entirely picked up by thermal generation as the 'balancing' form of generation. i.e. increasing generation in dry years, and scaling back in wet years. The reason why thermal generation performs this role is because:

- Other types of generation (i.e. geothermal and cogeneration) have much lower short-run marginal costs. Therefore, these will be dispatched ahead of thermal generation.
- The capital intensive nature of renewables means it is not economic to 'over-build' renewables such as wind, geothermal, or hydro such that they spill their energy during wet (or even normal) periods, in order that there is sufficient during dry periods.

As will be discussed later, this has significant implications for fossil fuel deliverability. The variation between the max and min levels for Q3 shown in Figure 33, is 2,900 GWh. If this were to be met through gas-fired generation with an average heat rate of 8.5 GJ/MWh (assuming a mix of CCGT and OCGT) gives rise to a swing requirement of 25 PJ. Assuming flat deliverability throughout the quarter, this gives rise to a variation in deliverability of 270 TJ/day. In reality, the deliverability requirement throughout the quarter is likely to be greater than this.

This variation in renewable generation is made more challenging because of the significant within-day and within-year variation in demand. As is illustrated in Figure 34, demand has a strong within-day and within-year pattern, giving rise to a need for some plant to operate for only some of the time.

Figure 34: Typical pattern of demand[66]



Hydro can meet much of this requirement for lower-capacity-factor generation by storing water during lower demand periods, for release in higher demand periods. However, there are constraints on its ability to do so, particularly on a seasonal basis[67]. Accordingly, even in 'normal' hydro inflow years, there is a requirement for some infrequently-used generation to be used for seasonal and within-day firming – i.e. generating in winter – and to meet the higher day-time demand.

Overall, the above dynamics give a requirement for some plant to operate infrequently to provide:

- Within-day peaking duties
- Within-year seasonal firming duties (i.e. meeting increased winter demand)
- Hydro (and wind) firming duties – i.e. meeting dry / wet year variation in renewable generation.

As previously noted, the capital intensive nature of renewables means it is generally not economic to 'over-build' renewables to provide such duties – i.e. spilling during much of the time, in order to have generation available for when it is required to perform the low capacity factor duties listed above.

That said, this is essentially an economic consideration, and if there were a very high CO_2 price in the future, it would be economic to over-build some renewables to a certain extent and incur the spill. However, as discussed later, there are limits to the extent to which increased spill from renewables would be the least cost option – even in futures of very high CO_2 prices.

Battery storage is an option to avoid costs of providing infrequently-used generation and network capacity to meet the 1-2% of periods that currently make up the critical peak system demand. Although the costs of battery storage are currently greater than this benefit, further reductions in the cost of

[66] It should be noted that the above figure shows average outcomes. There can be material variation around this on a day-to-day basis reflecting factors such as extremes in weather.
[67] This is because only the Waitaki scheme has significant storage of a size large enough to store water over a period of several months, and this is challenging given that the pattern of its inflows is generally anti-correlated with demand (i.e. Waitaki inflows are generally lowest in the winter periods).

batteries could bring them to the point where they deliver positive net-benefits – particularly in situations where peaking capacity costs are significant.[68]

In theory, it would be possible to have some batteries which were used to perform seasonal cycling – filling-up once in the summer to release again once in the winter. This would enable an even greater amount of generation to be undertaken by cheaper baseload plant.

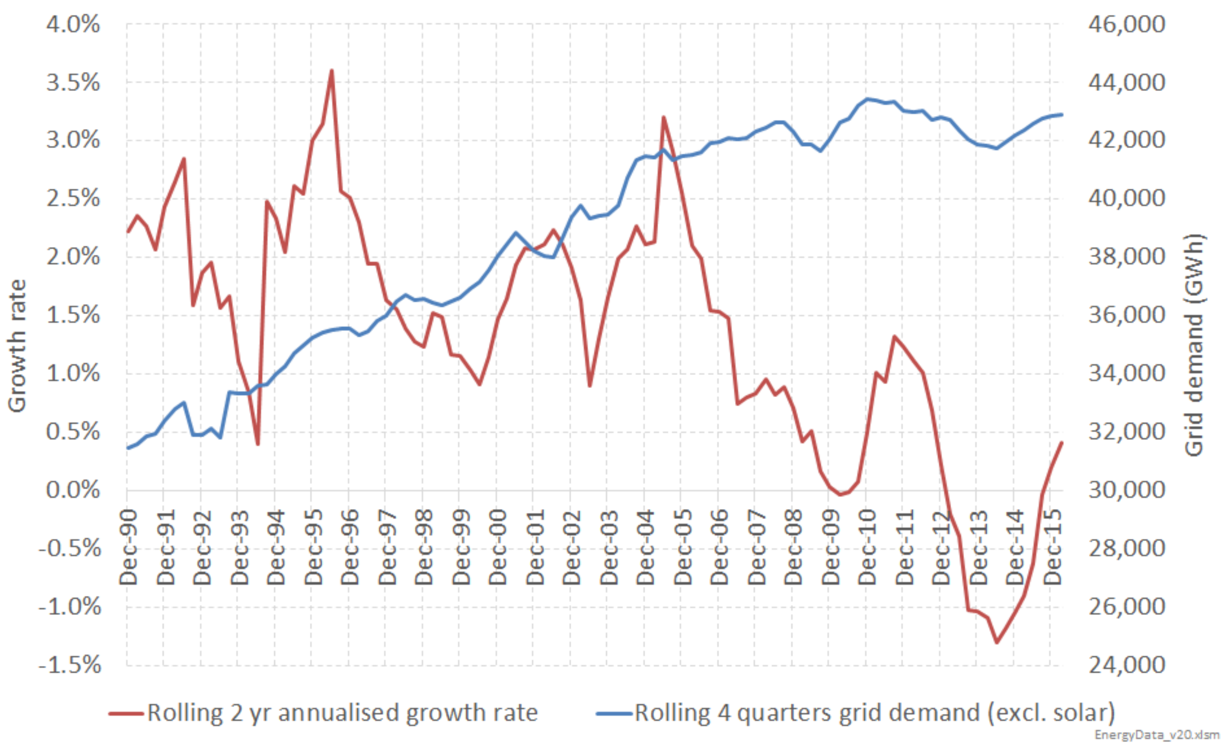
However, this is unlikely to be cost-effective in the foreseeable future. For example, if a battery is only just cost-effective to deliver benefits of daily arbitrage over the 365 days of the year, it will need to be much cheaper in order to be cost-effective for once-a-year seasonal cycling.

It is expected that batteries will possibly reduce the need for peaking gas power generation. However, it is unlikely that batteries will be able to replace the role that gas power generation plants play for providing dry year generation.

5.3.2 Variations in electricity demand

Figure 35 shows the historical variation in grid demand.

Figure 35: Historical grid demand



From 1990 through to mid-2008, there was generally steady growth of approximately 1.8% on average.[69]

---

[68] There is significant variation in the range of potential avoided peak capacity costs. This is due to a variety of factors including:
1) Uncertainty of the Long Run Marginal Cost of network capacity investment to meet peak demand growth. This is due to relatively little analysis having been undertaken of this matter in New Zealand. Australian LRMC estimates using an Australian regulatory-prescribed methodology are significantly higher than the few estimates found in New Zealand (noting that such estimates are not generally on a like-for-like basis).
2) Variation in the extent of spare capacity on different New Zealand networks (spatially and over time).
3) Uncertainty over the extent to which New Zealand's current situation of surplus generation capacity will persist or reverse, though changes relating to the potential retirement of the Huntly Rankine units, loss of major sources of demand such as the Tiwai aluminium smelter, or other generation or demand changes.

[69] Some of the year-to-year variations in this period were due to demand curtailment during dry years.

However, from mid-2008 onwards there have been periods of sustained demand falls due to a number of factors:

- The Tiwai transformer failure in 2008/9 which significantly cut demand for the Tiwai smelter (which accounts for approximately 13% of national demand)
- The Christchurch earthquake in 2011 which significantly reduced demand in Christchurch city, and which has taken a long time to recover.
- The global financial crisis (GFC) from 2008 onwards which affected demand from many business sectors
- Some other significant losses of demand – notably the retirement of one of the two Norske Skog paper mills in 2013

It is likely also that energy efficiency has impacted on demand during this period, being a consequence both of government initiatives (particularly those led by EECA such as Warm Up New Zealand), as well as a general response from consumers responding to the material rise in energy prices that have been experienced since 2000.

More recently, since the middle of 2013 it can be seen that demand has picked-up again, with rates of demand growth approaching that seen before the GFC.

In the same way that thermal generation picks up the variation in renewable output, thermal generation has also picked-up the variation in demand – particularly those unanticipated movements in demand on a short- to medium-term basis (i.e. 1-2 years), where demand changes cannot be easily met by building new generation.

Looking forward, there is considerable uncertainty over future demand – particularly with respect to the Tiwai aluminium smelter, but also with respect to the general level of demand growth. This is explored in the later section considering possible futures for gas-fired power generation.

5.3.3 Changes in the relative competitiveness between types of power stations

Relative competitiveness of renewables and thermal

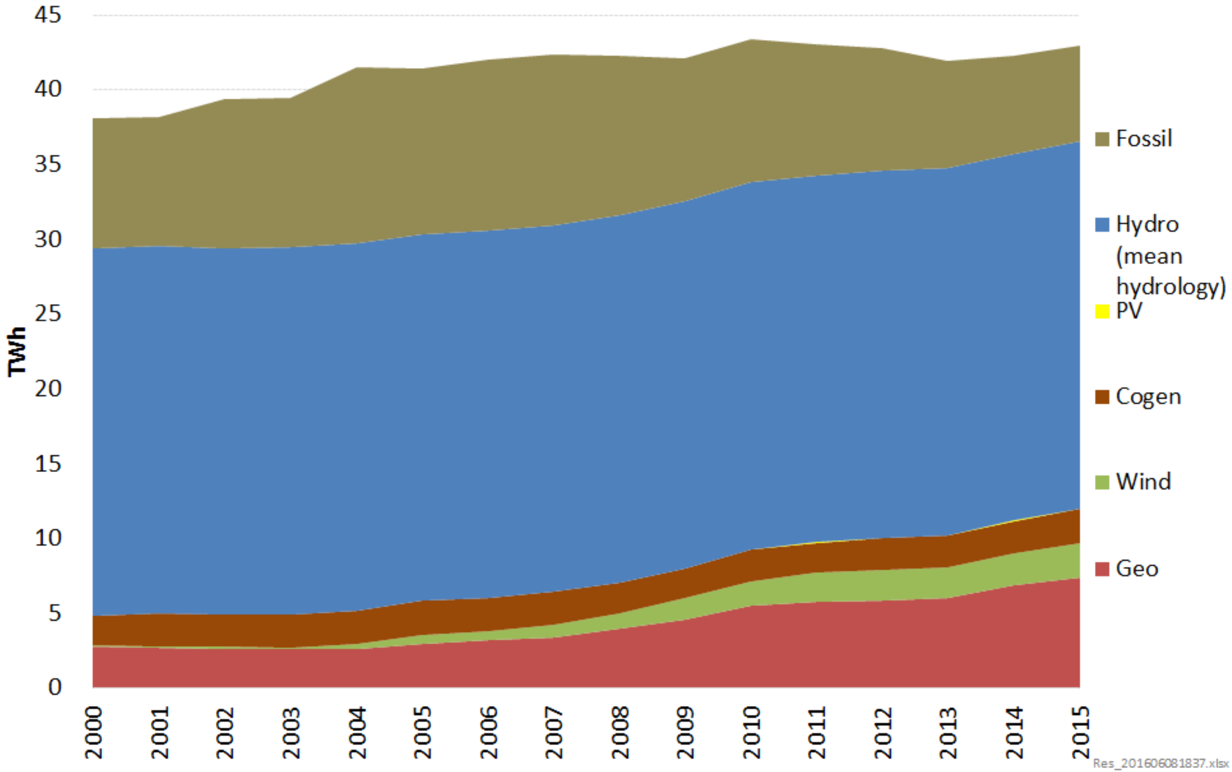
Much of the increase in gas demand from the mid-1990s through to 2007 was associated with the development of new baseload gas-fired power stations in the form of combined-cycle gas turbines (CCGTs). These plant were built to meet the steady growth in demand over that period and, given the relatively low gas price environment that existed until the early 2000s, were cheaper than the alternatives: new coal-fired generation, or new renewable generation (wind, geothermal, hydro).

However, since the mid-2000s, New Zealand has transitioned to a point where the cheapest form of new baseload generation is renewable – either wind or geothermal. This reflects a significant reduction in the cost of some of these technologies (particularly wind), as well as a material increase in New Zealand's gas price (and the introduction of a price of CO_2).

As a consequence, new baseload generation from 2007 onwards has been renewable – predominantly wind and geothermal.

It is potentially the case that some of these new renewable projects were part of a general 'over-build' of new renewables in the 2008-2015 period. This is due to new wind and geothermal projects being committed based on expectations of higher demand growth and CO_2 prices than actually eventuated. As is illustrated in Figure 36, this has had the effect of squeezing out some existing fossil generation.

Figure 36: Historical generation by plant type, but with mean hydrology hydro gen[70]



It is likely that some of this displacement of existing fossil was economic given underlying fuel and CO_2 prices – particularly the displacement of some of the Huntly Rankine generation from baseload duties. However, it is also likely that some displacement was not economic. i.e. given the fuel and CO_2 prices that existed over this period, it would have been lower cost to continue to generate using existing fossil stations (which have sunk capital costs) rather than build new renewable power stations.

Of course, if the 'true' societal cost of CO_2 is significantly higher than the relatively low CO_2 prices that have occurred over the last six years, then some of this displacement is likely to have been economic from a public perspective. This is explored further later in this section.

Relative competitiveness between coal and gas-fired power stations

As a result of the squeezing out of fossil stations generally that has occurred over the last 5-6 years, a number of existing fossil units have closed:

- Two of the 250 MW Huntly Rankine units (in 2012 and 2014)
- The 365 MW Otahuhu B CCGT in September 2015
- The 125 MW Southdown CCGT in December 2015

It is notable that the two CCGTs closed, rather than the remaining two Huntly Rankine units. This reflects the fact that for some low-capacity factor duties – particularly dry-year hydro firming – coal is a cheaper fuel to provide infrequently-used energy than gas.

This is because the sources of gas flexibility are more expensive for delivering flexibility over the time-frame of years (i.e. to manage dry/wet year variability). These source of gas flexibility are:

[70] For this analysis, actual geothermal, wind and cogeneration is used, but the hydro generation that would be expected in a mean inflow year. Fossil generation is simply the balancing item between total historical grid demand for the year, and the output from these other types of generation.

- Swing from gas production. This can be expensive for liquids-rich fields as it requires forgoing oil production and revenues for most periods, in order to have sufficient production capacity in dry periods.
- Re-injecting gas. This can help address the foregone oil revenues from swing in gas production, but incurs the cost of foregone gas sales, higher capital costs, and extended field operating costs.
- Gas storage. At present, this is only provided by the Ahuroa gas storage facility operated by Contact. While the economics of gas storage look favourable for delivering seasonal flexibility, they become significantly more expensive for providing multi-year flexibility (e.g. filling up in a 1-in-5 year wet year, say, for release in a 1-in-5 year dry year).
- Gas demand diversion. The only source of gas demand of a size large enough to provide the amount of gas required to meet dry/wet year flex is the methanol production facilities owned by Methanex. This could be expensive as the price which Methanex would be willing to receive for not consuming gas will be set by the opportunity cost of producing the methanol from somewhere else, or foregoing methanol sales altogether. Analysis of historical methanol prices suggests this could be a relatively high cost source of gas flexibility.

In contrast, the cost of flexibility for based on coal for dry-year duties is considerably lower. This reflects two key factors:

- the working capital cost of storing coal in a stockpile is materially lower than the gas flexibility costs detailed above
- the size of the coal stockpile can be relatively small relative to the size of the flexibility requirement, because there is a relatively liquid international coal market, and it is possible to purchase significant quantities of coal on spot with relatively little notice period (of the order of 3-4 months).

This much lower cost of coal fuel flexibility outweighs the worse fuel efficiency of the Rankine units compared to CCGTs, and the higher fixed O&M costs of keeping the Rankine units operational. Even with relatively high CO_2 prices, this fuel flexibility advantage means the Rankine units are lower cost options for performing dry-year duties.

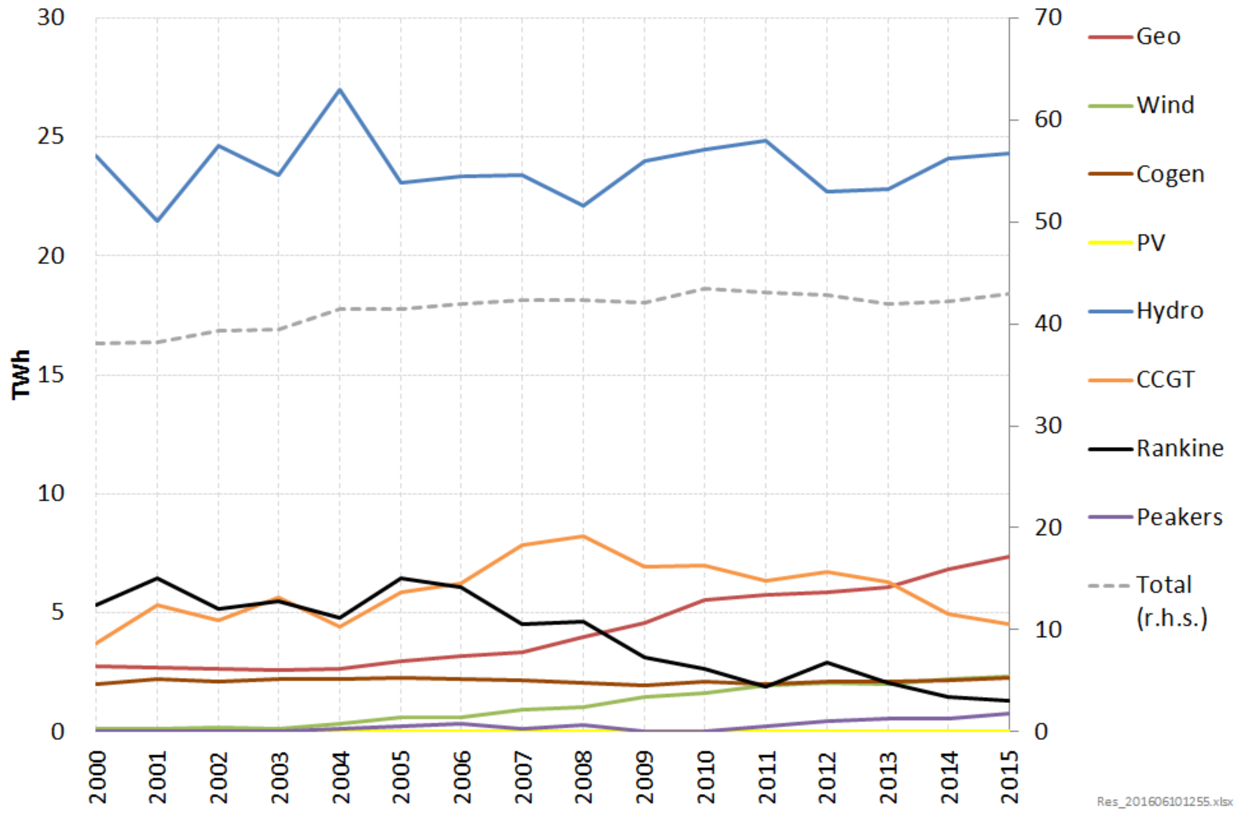
Ironically, therefore, it is New Zealand's relatively large reliance on hydro generation which is keeping New Zealand's last remaining coal-fired station going.

That said, in August 2015 Genesis announced it was going to retire the remaining two Huntly Rankine units by the end of 2018. It postponed this closure date to 2022 when it secured hedge contracts from a number of other generators. It is potentially the case that the Rankine units could be retired at that point. This would have significant implications on the gas sector in terms of increasing the requirement for fuel deliverability. This issue is explored further in section 5.4.

Relative competitiveness between different types of gas-fired power stations

It is notable that during the period where CCGTs have been declining in output, the output from OCGTs has been increasing. This is shown in Figure 37.

Figure 37: Historical generation by fuel type



Thus, even though OCGTs have a worse fuel efficiency than CCGTs, OCGTs are significantly more flexible and lower cost than CCGGTs in terms of meeting within-day variations in demand.

Thus CCGTs have relatively high start-up costs, and high minimum generation levels. This means that for many periods, CCGTs can be operating during periods where the market price is below their short-run marginal cost.

Accordingly, as renewables have displaced CCGTs from baseload generation duties, OCGTs are becoming lower cost options than CCGTs for these lower capacity-factor modes of operation.

This dynamic is likely to result in future OCGTs being developed to meet growth in the requirement for flexible generation rather than CCGTs.

5.4 Projections of gas demand for power generation

Concept's suite of electricity and gas market models were used to examine possible futures for gas for the power generation sector.

As well as seeking to project likely power station gas demand, the models were used to examine the sensitivity of outcomes to a number of key drivers:

- Demand – both the general rate of demand growth, as well as specific examination of a potential Tiwai exit from 2019[71]
- Potential retirement of the Huntly Rankine units, through simulating the forced[72] retirement of the remaining two units, once the existing contracts covering their output expire after 2022

[71] This is a scenario assumption as the smelter has the ability to terminate the contract at any point from 1-Jan-18, provided it gives 12 months' notice.

[72] Whereas the model generally only retires thermal units endogenously (i.e. through undertaking an evaluation as to whether retirement of a unit would be least-cost given the specifics of the scenario (e.g. demand, fuel and CO_2 prices)), it is possible to exogenously force the retirement of a unit at a particularly date on a scenario basis – irrespective of whether the model determines whether this would be a least cost outcome.

* CO_2 prices – through examining a range of different CO_2 price scenarios
* Coal vs gas economics – through examining scenarios with different gas prices (both the general level, and the cost of providing flexibility (or swing)).

Various combinations of the above drivers were examined resulting in 18 scenarios overall.

It should be noted that this modelling projects the least-cost pattern of generation build and operation given the underlying scenario inputs – particularly fuel and CO_2 prices, the cost of new renewables technologies, and demand growth. As is shown in detail in section 5.4.6 on page 83, many of these scenarios project levels of renewables generation which are lower than the government's current target of 90% renewables by 2025. This may inform considerations as to the relatively likelihood of the different scenarios, particularly with respect to CO_2 prices – noting that higher CO_2 price scenarios result in the model projecting much higher levels of renewable development.

5.4.1 Central projection

Our central case is for the Tiwai smelter to continue to operate at 572 MW, and for the Huntly Rankine units to remain available after 2022.

Figure 38 and Figure 39 show electricity production from different sources under the central scenario projection. In the early years of the projection, it shows growing power demand is met by increased use of lightly utilised thermals – particularly the TCC CCGT and the Huntly Rankine units.

However, beyond 2020, additional investment in new generation capacity is required – geothermal and wind in particular. Generation from the thermal fleet is largely stabilised at the then prevailing level – with only a few new open cycle gas turbine (OCGT) plants being developed to meet peak capacity requirements. None of the existing thermals (including the TCC CCGT and remaining two Huntly Rankine units) are projected to become uneconomic and therefore retire under the central projection.

Figure 38: Generation volumes by plant type for Central scenario – line graph

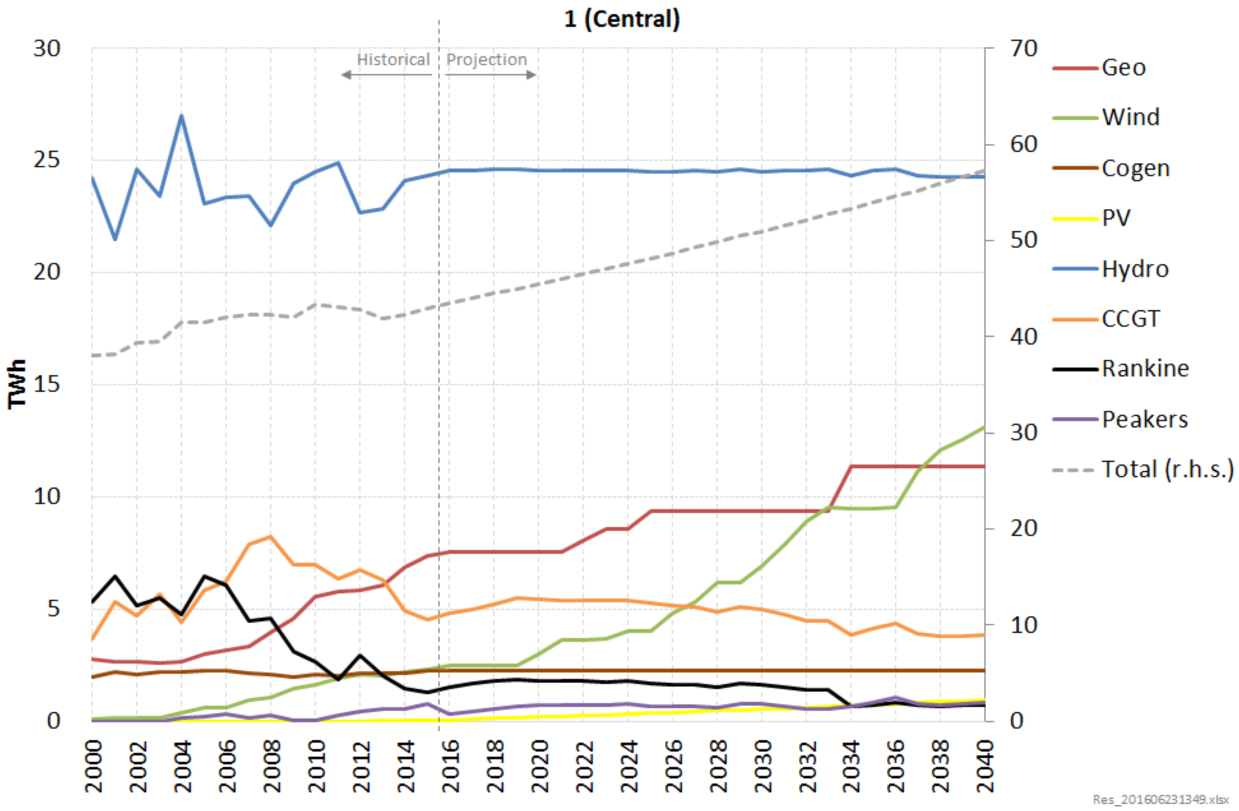
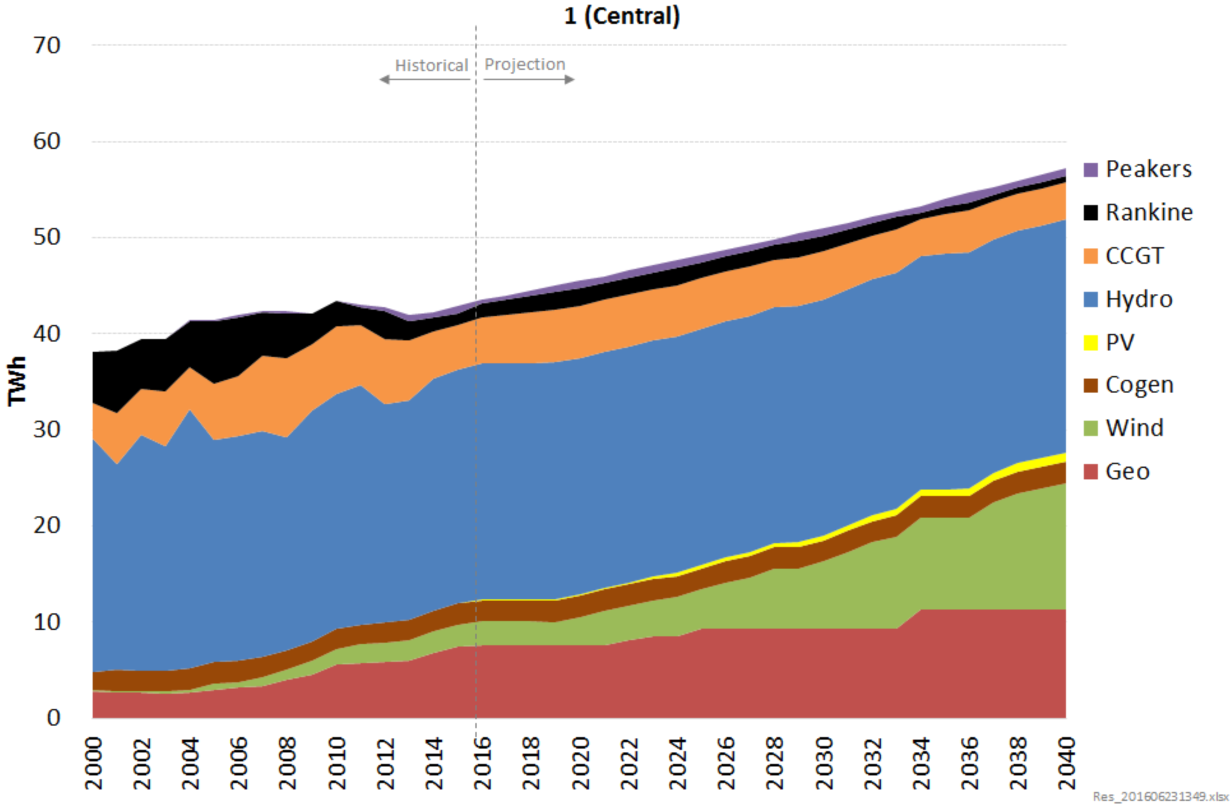


Figure 39: Generation volumes by plant type for Central scenario – area graph

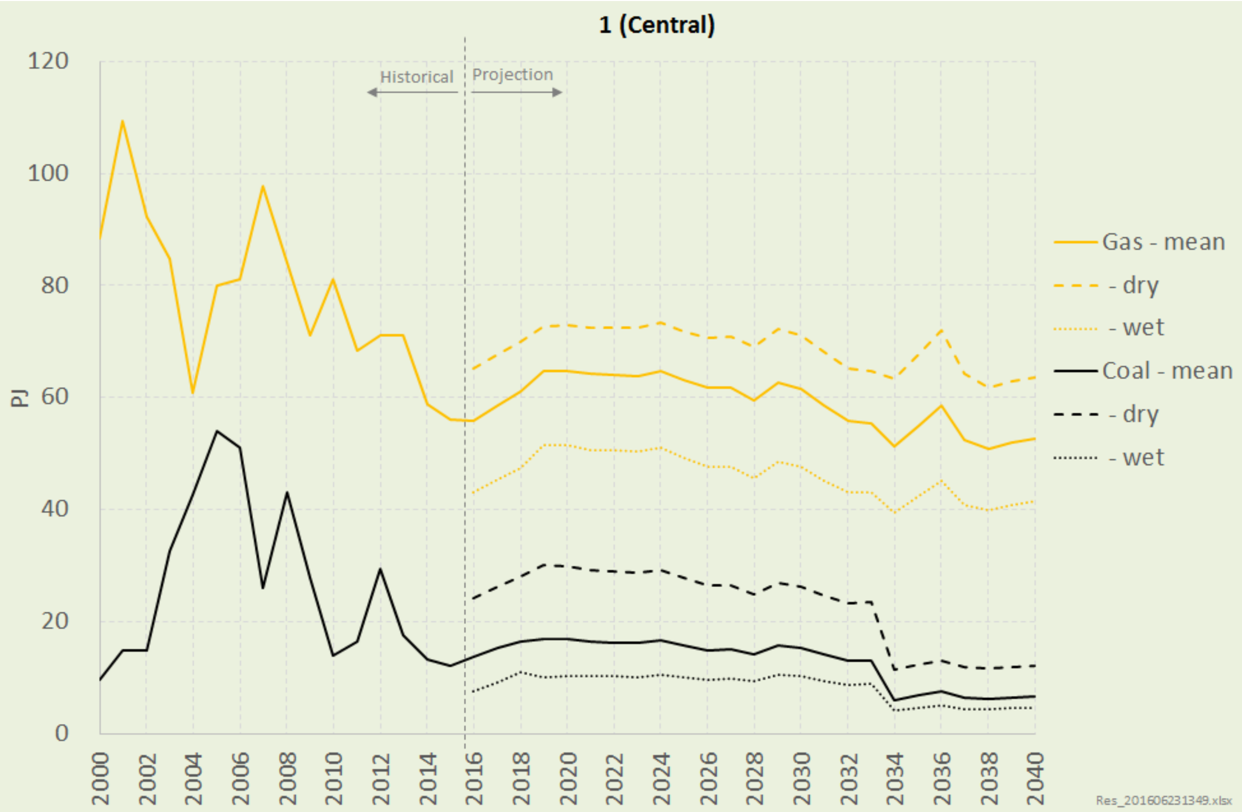


Source: Concept analysis

Figure 40 shows the resultant thermal fuel requirements associated with the central projection – both in terms of fuel burn in a mean hydrology year, as well as showing projected fuel requirements in 1-in-10 dry and wet years.

It shows increasing fuel volumes in the next few years associated with electricity demand growth predominantly being met by increased use of under-utilised thermals. However, beyond 2019, fuel demand levels off as power demand growth is predominantly met by new baseload renewables. In the longer term, there is a gradual decline in thermal fuel requirements as new renewables are built to displace existing thermals from some of their higher capacity factor modes of operation – reflecting both the projected ongoing cost reductions in wind technology, and the projected ongoing increase in CO_2 prices.

Figure 40: Fuel volumes for the Central scenario



Source: Concept analysis

5.4.2 Sensitivity case - full closure of Tiwai smelter

Given the uncertainty around the future operation of the Tiwai smelter, we have considered a case where the smelter ceases operation altogether from 2019.

Figure 41 shows that the majority of this loss of demand is borne by the fossil stations – being a mix of the Huntly Rankine units and the CCGTs. Although not shown in the graph, the model projects the closure of one of the remaining Rankine units, and the TCC CCGT. However, it keeps one of the Rankine units open.

Figure 41: Projected generation under a Tiwai closure scenario

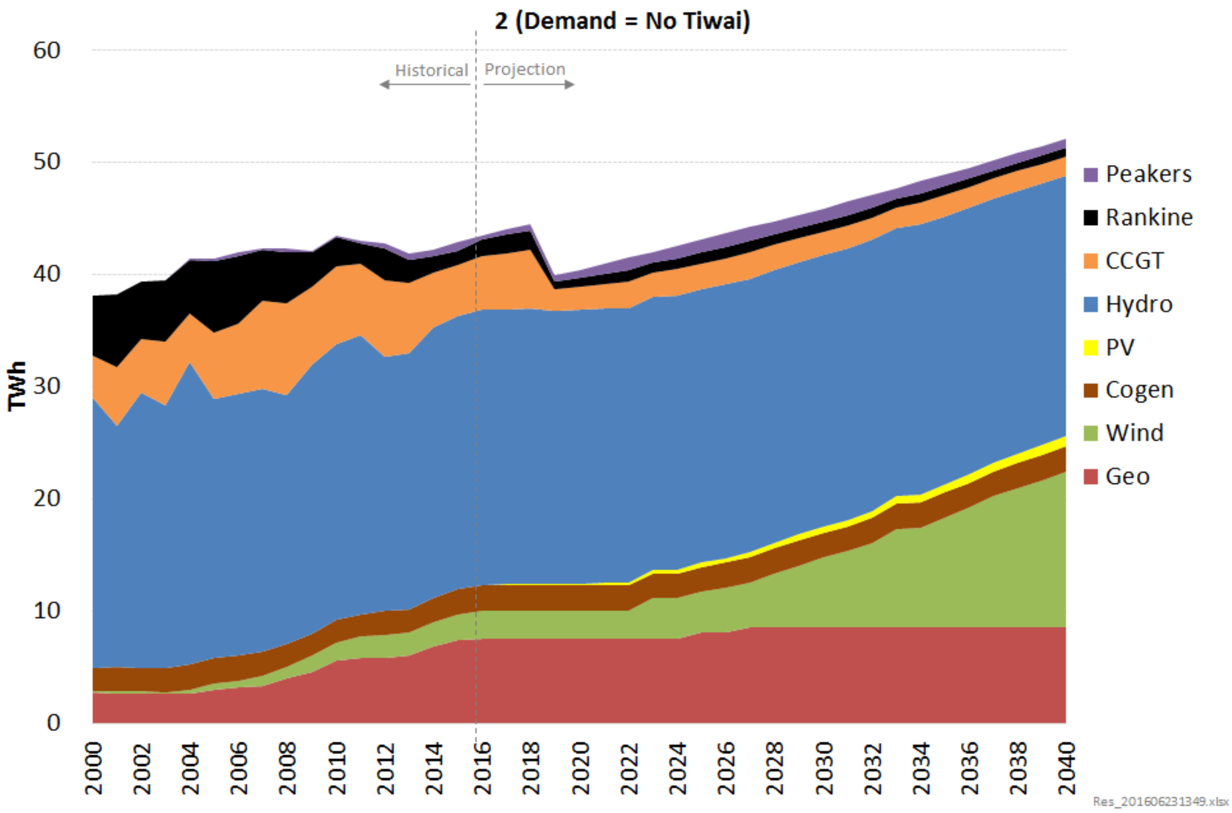
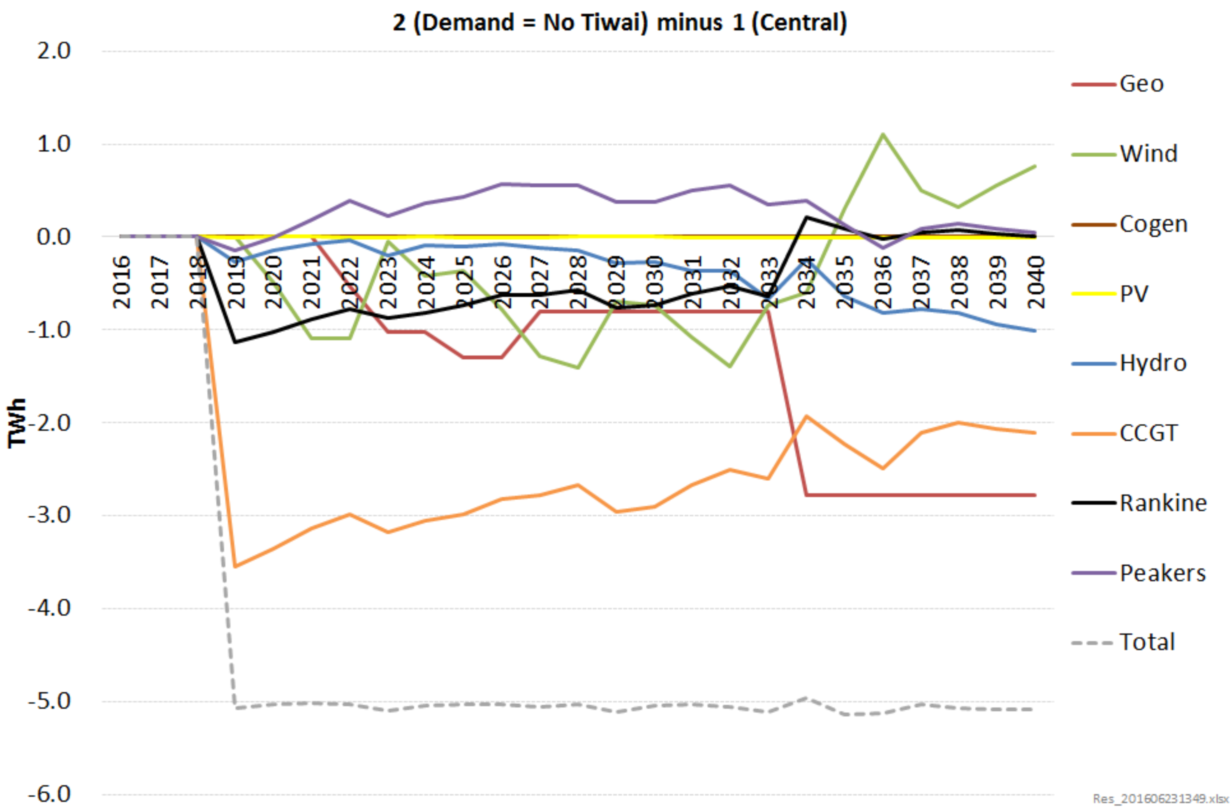


Figure 42 further illustrates what type of plant are impacted by the closure of Tiwai.

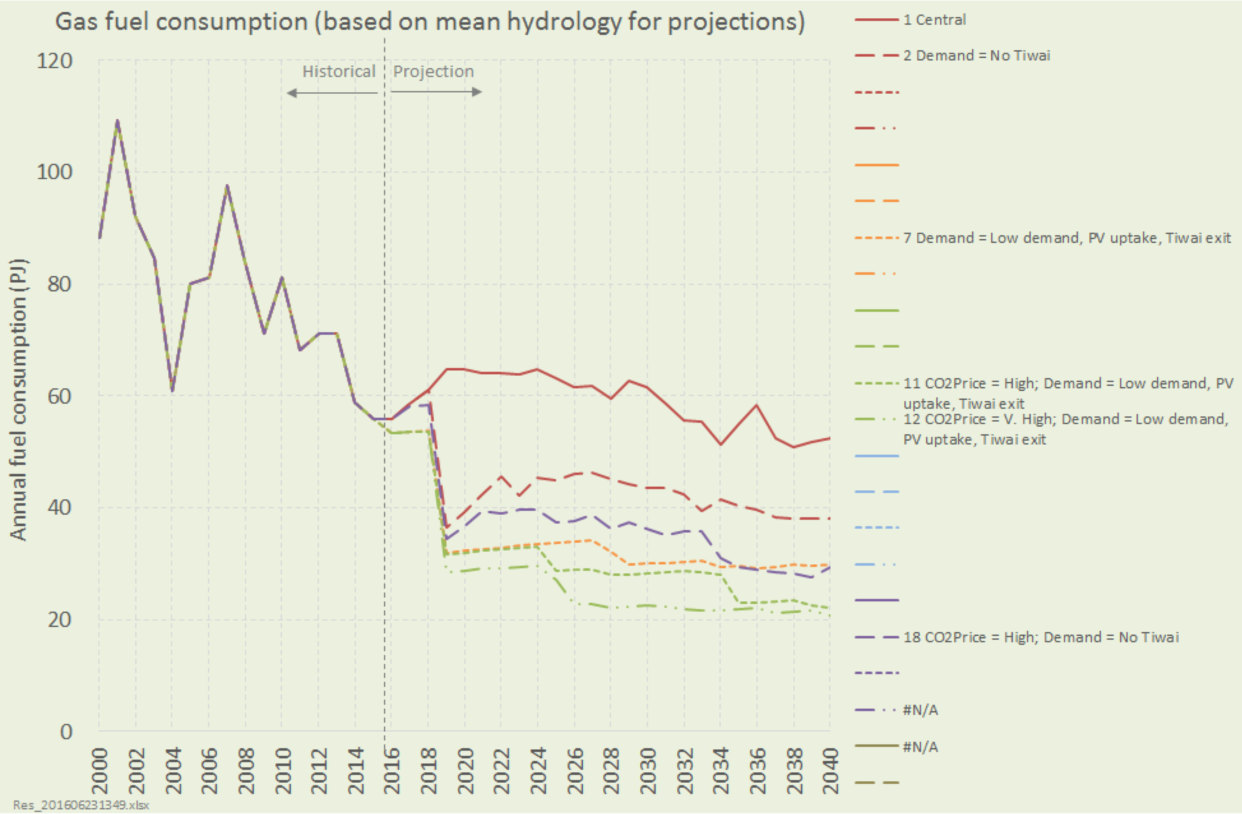
Figure 42: Difference in generation between the No Tiwai scenario and the Central scenario



Thus, the majority of the lost demand is borne by the CCGTs and (to a much lesser extent) the Huntly Rankine units. However, the drop in demand also postpones the development of some wind and geothermal. In addition, in the latter years, with the loss of the TCC CCGT and Huntly Rankine, there is not as much thermal flex available on the system, with the result that some of the dry/wet year required flex is met by spill (as indicated by the reduction in the hydro line). The loss of the CCGT and Rankine unit also brings forward the development of OCGT peakers to provide some of the seasonal and diurnal flex generation that these larger thermal units would have provided.

In terms of the impact on gas demand, Figure 43 shows the projected gas demand (under mean hydrology) for the central case (red line) and all those scenarios which feature a Tiwai closure (including considering different CO_2 prices and non-Tiwai demand forecasts).

Figure 43: Gas demand under cases where Tiwai smelter closes



Source: Concept analysis

As expected, the analysis shows that closure of the Tiwai smelter would primarily affect thermal power stations (albeit with some increased hydro spill), and would immediately reduce the demand for thermal fuel (gas + coal) by approximately 35 to 37 PJ per year. Depending on the extent to which this impact is shared across the Huntly Rankine units, gas-fired CCGTs and OCGTs, this would reduce gas demand by between 23 to 28 PJ per year relative to the central case. In this way, the Tiwai smelter can be thought of as the second largest gas consumer after Methanex.

In scenarios where the closure of the Huntly Rankine units is not exogenously specified, the model generally keeps one of the Rankine units open (even after Tiwai has closed). This is because closure of the smelter would reduce baseload electricity demand, and it is more economic to retain the Rankine units for low capacity factor operation (particularly dry-year duties), and shut gas-fired plant such as the TCC CCGT (which are more suited to higher capacity factor modes of operation).

However, it is potentially the case that the economics of the Huntly Rankine units are such that the majority of savings in fixed O&M costs will only be realised through the closure of the entire station. This may make the projections which only have one Rankine unit retiring less likely, either resulting in both units remaining open, or both being retired.

5.4.3 Sensitivity case - closure of the Huntly Rankine units (Tiwai remains open)

As discussed earlier, although we consider it likely that the Huntly Rankine units will remain in operation, there is a possibility that Genesis will retire the units once their existing contracts expire at the end of 2022.

We have therefore considered two scenarios where this occurs – closure of both units at the end of 2022, and closure of the both units at the end of 2026 (simulating another four-year extension). Variants of these scenarios were also run with higher CO_2 prices.

As is shown in Figure 44 and Figure 45 (considering the scenario with Huntly retiring at the end of 2022), the type of plant which largely replaces the generation from Huntly is gas-fired peaking plant. This reflects the fact that the Huntly Rankine units are largely providing infrequently-used generation to provide dry-year and winter generation – and the next most economic form of generation to perform such duties are OCGTs.

Figure 44: Projected generation in the Huntly closure scenario (mean hydrology for future years)

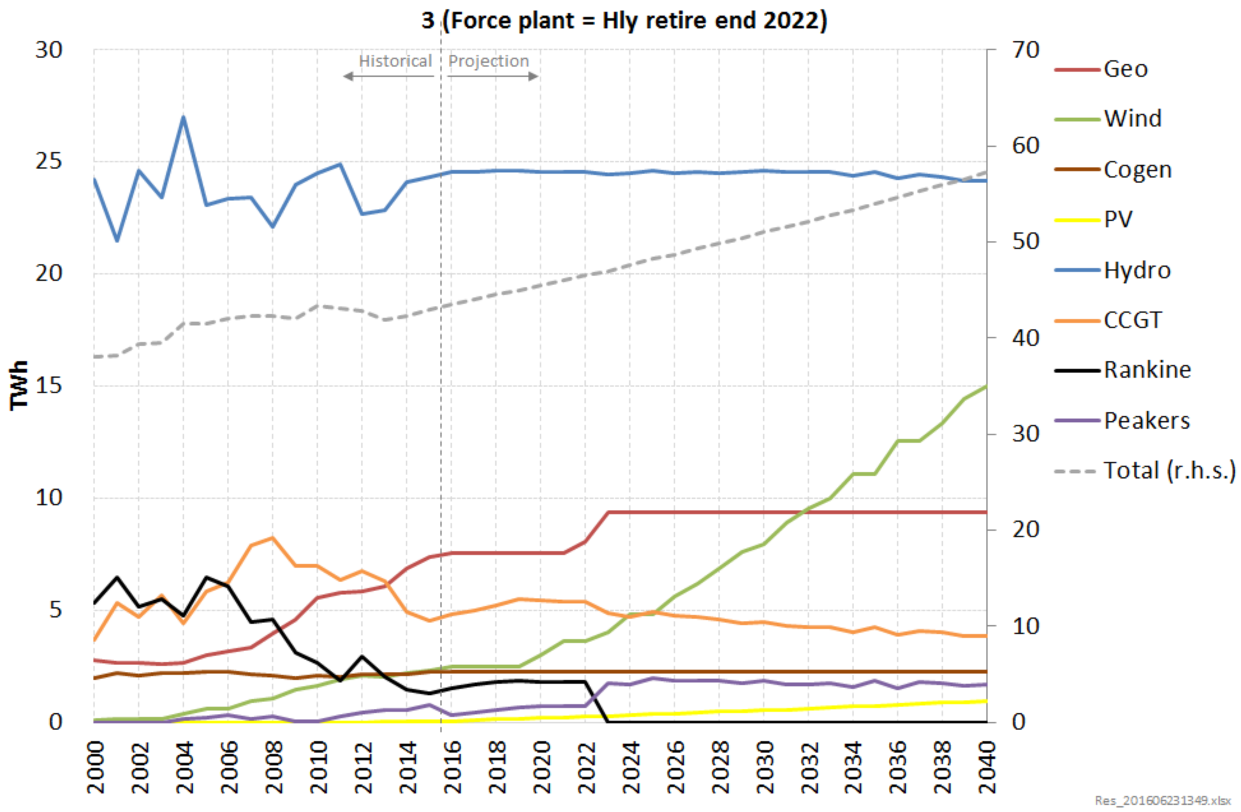


Figure 45: Projected change in generation due to closure of the Huntly Rankine units

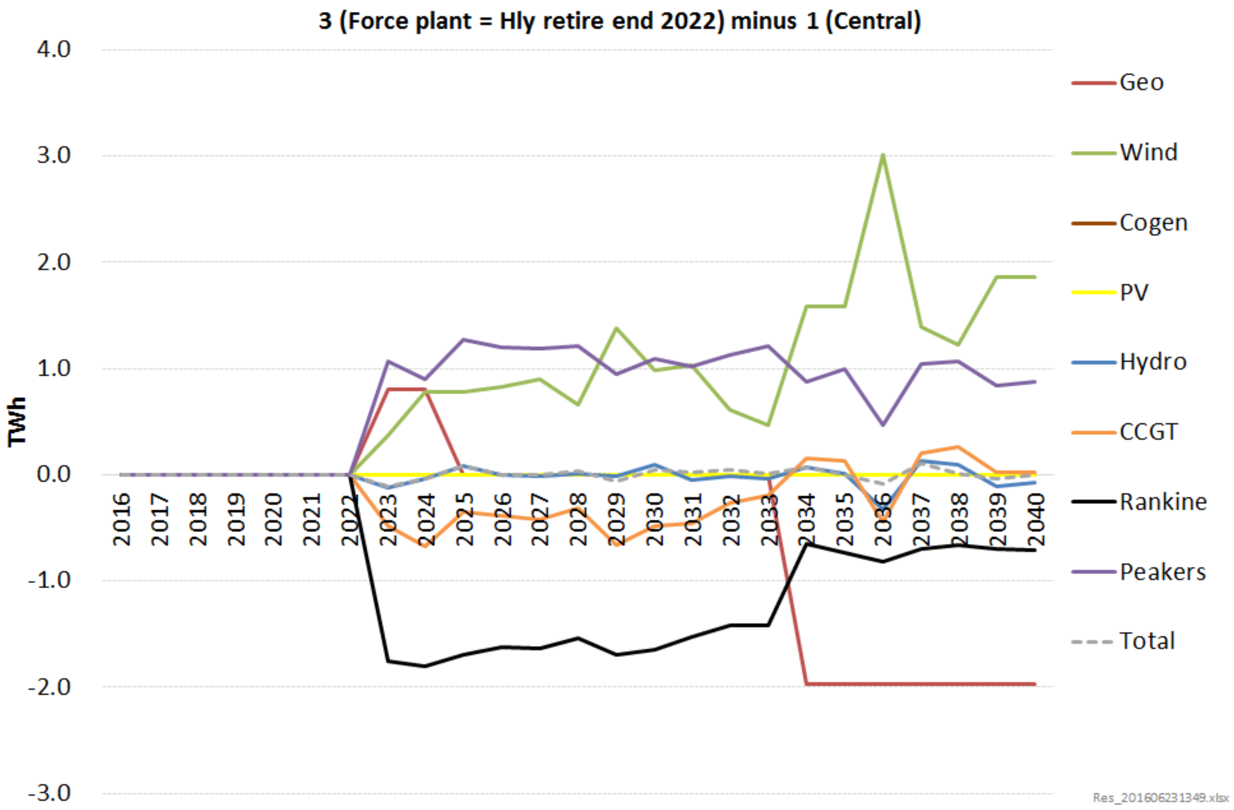
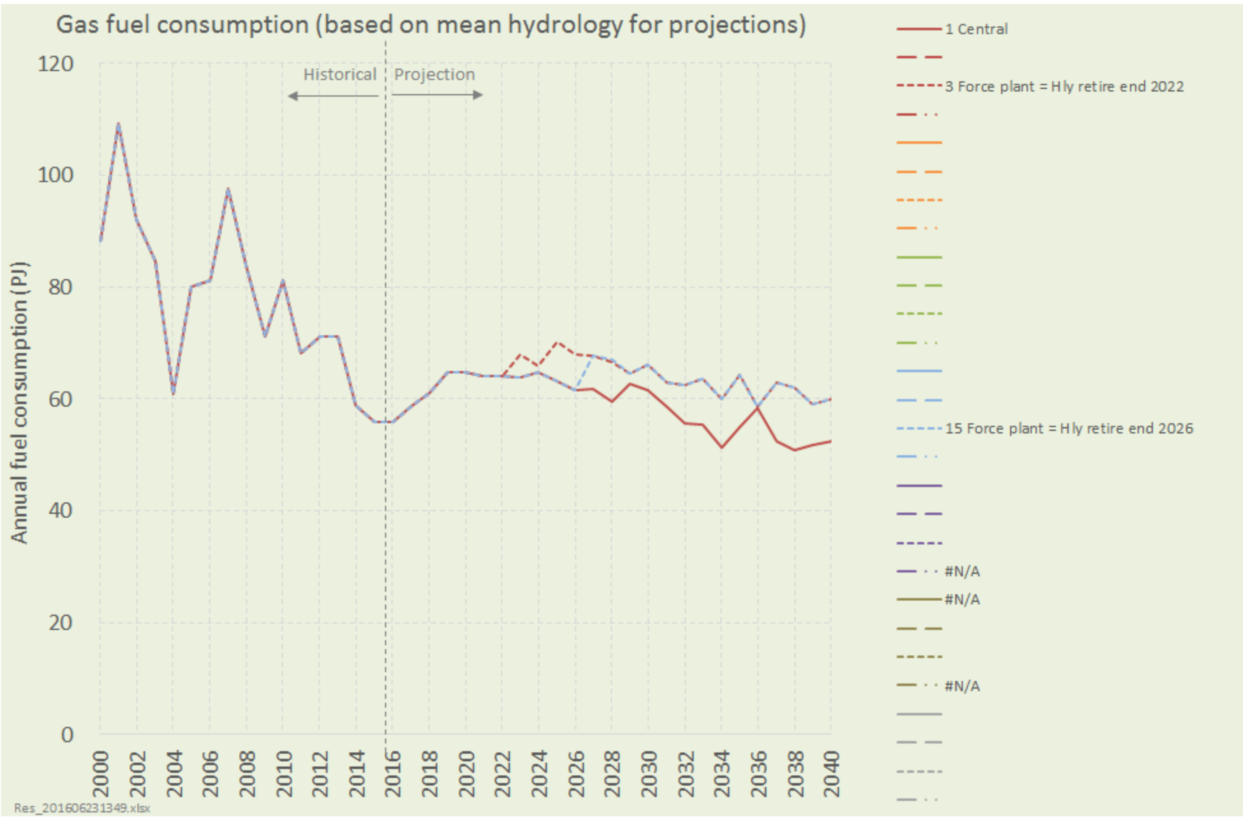


Figure 46 shows the projected gas demand (under mean hydrology) for the central case and these cases where the Rankine units close.

Figure 46: Fuel impact of closure of Rankine units (Tiwai smelter continues)



Source: Concept analysis

The analysis shows that closure of the Huntly Rankine units is expected to materially lift demand for gas relative to the central case. The implications for gas deliverability are explored later.

5.4.4 CO_2 price sensitivities

As shown in Figure 47, a range of different CO_2 prices were considered. The 'Mid' projection was used in the Central scenario.

Figure 47: CO2 price projections[73]

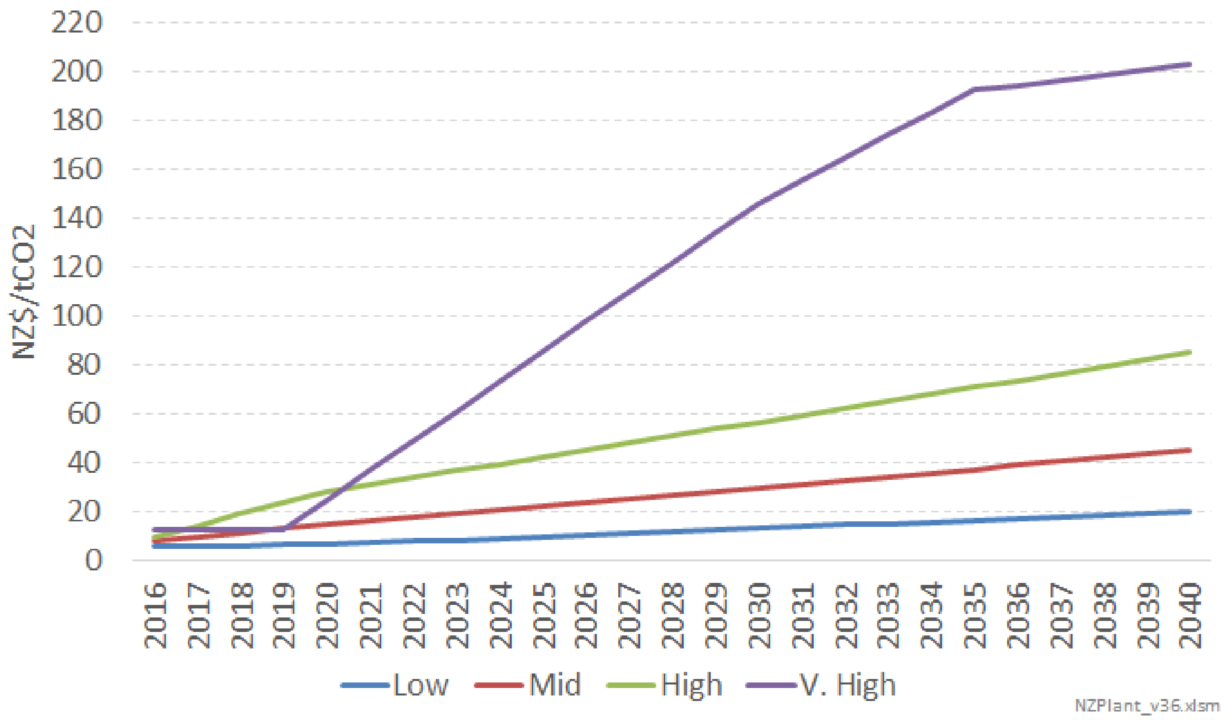


Figure 48 and Figure 49 show the projected outcomes for the scenario with very high CO_2 prices.

As can be seen, in such a future, there would be significantly more wind generation developed. This would displace all of the coal-fired Rankine generation and much (but not all) of the gas-fired generation. Less geothermal would be developed as geothermal stations themselves emit CO_2 (approximately 1/3 of the amount of a CCGT).

Further, as is indicated by the reduction in hydro generation, much of the flex for meeting dry-year and seasonal requirements will come from 'over-building' renewables and spilling for much of the time.

[73] The Mid and High CO_2 price projections were based on the 'Kayak' and 'Waka' projections from the Business Energy Council's recent Energy Scenarios. The Very High CO_2 price projection was taken from the 2015 MBIE EDGS projection – which in turn was taken from the IEA's "2 degrees" scenario.

Figure 48: Projected generation under the Very High CO_2 price scenario

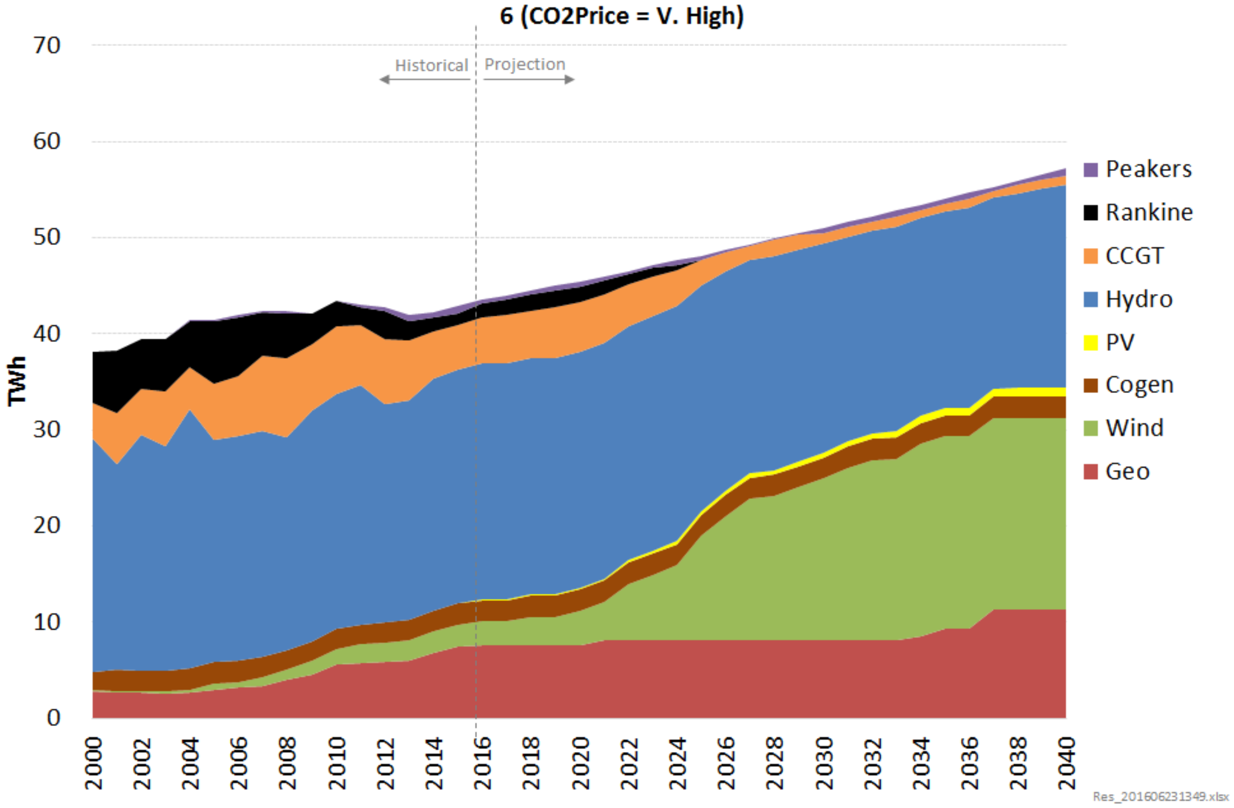
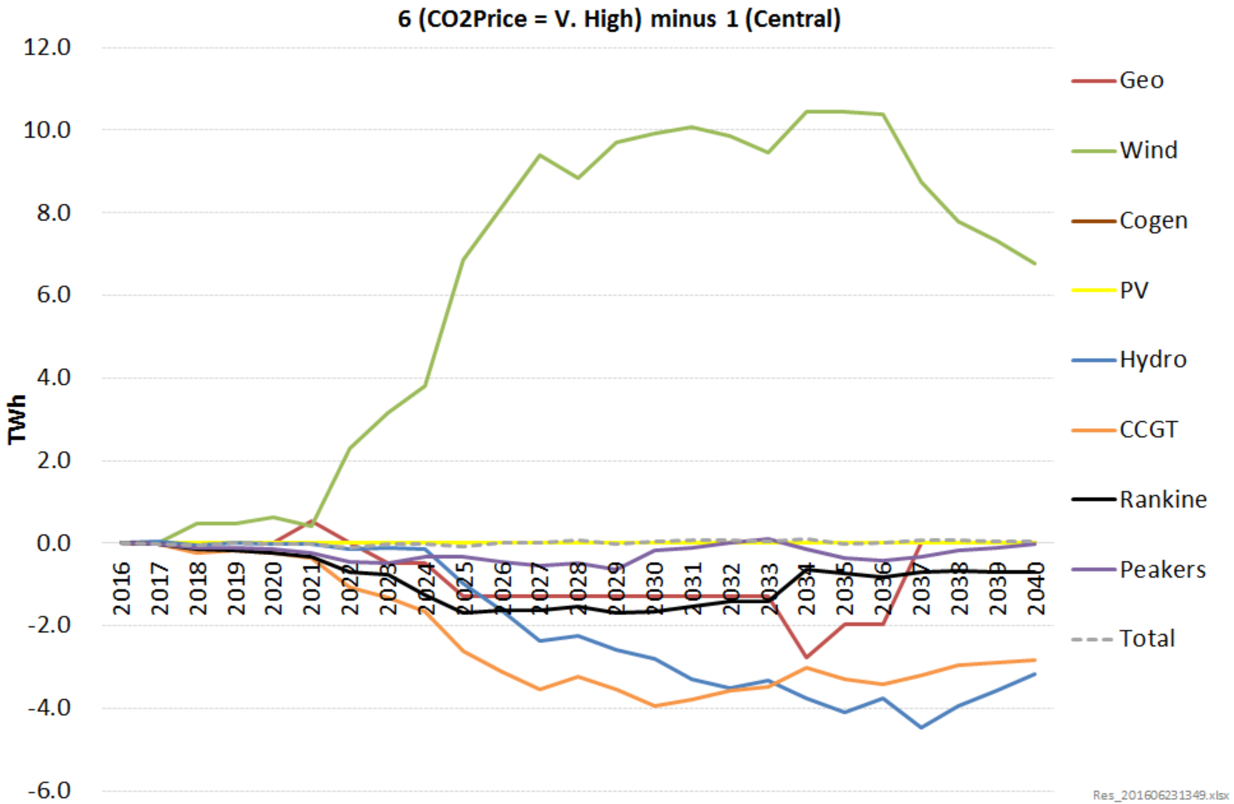


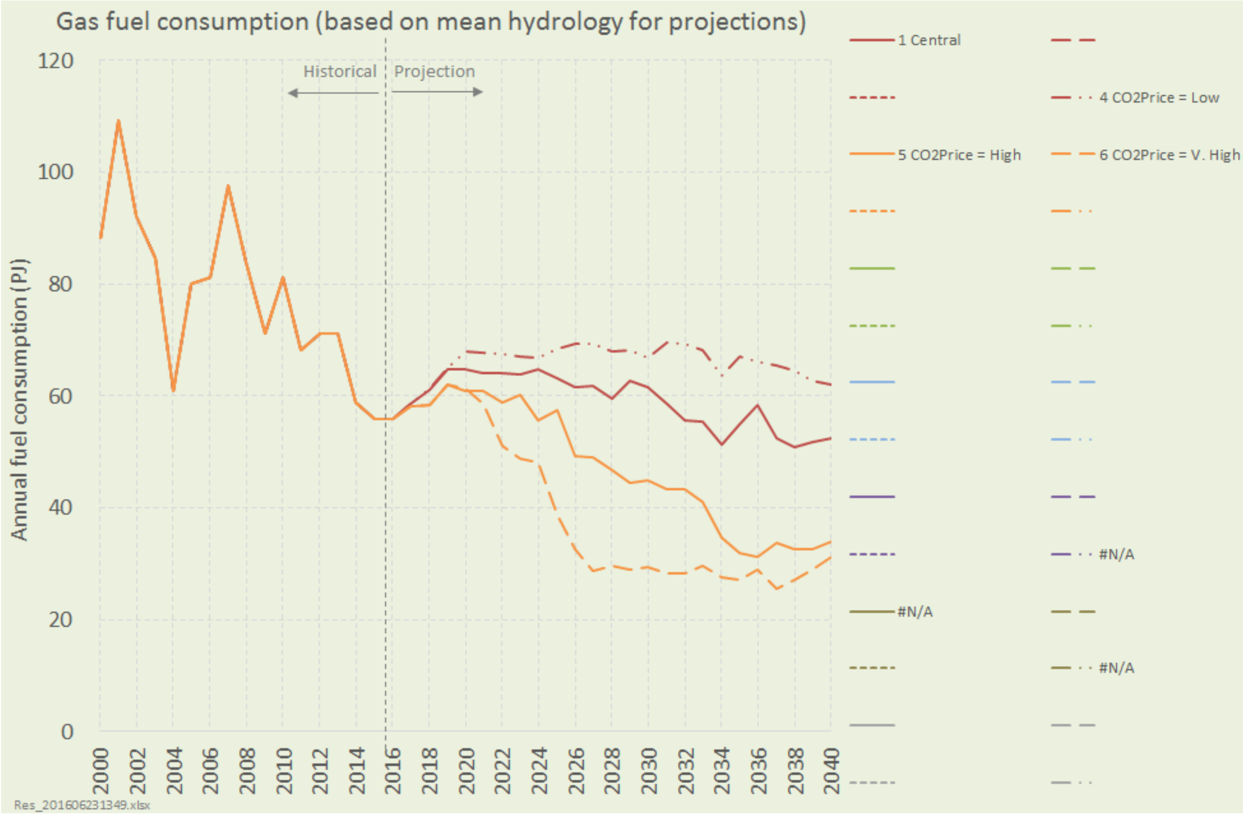
Figure 49: Difference in generation arising from the Very High CO_2 price scenario



Ultimately, even with high CO_2 prices, a point will be reached where the economics of building renewable generation to sit idle most of the time become prohibitive. This is why a residual amount of gas-fired generation is expected to be required to provide these infrequently-used duties.

The resultant projections of gas demand for power generation under this range of different CO_2 price scenarios are shown in Figure 50

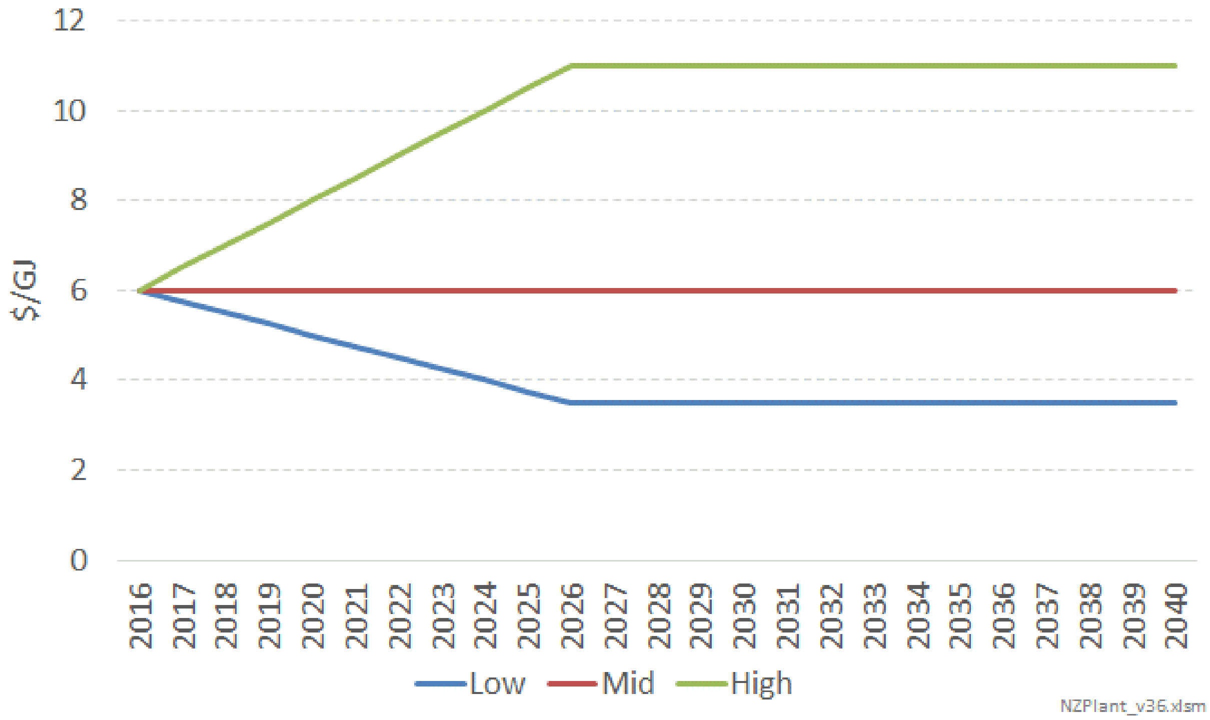
Figure 50: Projected gas demand for power generation under different CO2 price scenarios



5.4.5 Gas price sensitivities

Sensitivities were run that assumed wholesale gas prices transitioned toward levels in the 'Scarce' and 'Plentiful' scenarios set out in section 2.2. In both cases, we have assumed a straight line transition over the period to 2026 as shown in Figure 51 below, with prices remaining at those levels from that point forward.

Figure 51: Gas price scenarios



As discussed in section 2, it is unlikely that prices would persistently remain at these ‘extreme’ levels in the long-term, as the relative scarcity / surplus would tend to result in countervailing economic pressures which would be likely to bring the market back into a more balanced position.

Nonetheless, the power generation scenarios using these extreme prices provide useful ‘bookends’ to examine the theoretical range of potential outcomes.

Plentiful gas scenario

The following figures illustrate that a sustained low gas price future is projected to result in increased generation from gas-fired plant. In particular, it would likely result in the closure of the Huntly Rankine units with their replacement by gas-fired OCGTs.

Further, the remaining two CCGTs would largely move into baseload mode – although still providing downward flex in particularly wet years – with increased development of OCGTs to provide the mid-merit duties.

Although gas prices are low on a sustained basis, the scenario doesn’t see the development of new baseload CCGTs, in large part due to:

- Increased baseload operation largely being met by the existing CCGTs in the short- to medium-term
- Expectations of higher CO_2 prices in the longer term, coupled with projected real falls in the cost of baseload renewable options, particularly wind, making renewables more cost effective than new CCGTs.

Figure 52: Projected generation under a sustained low gas price scenario – area graph

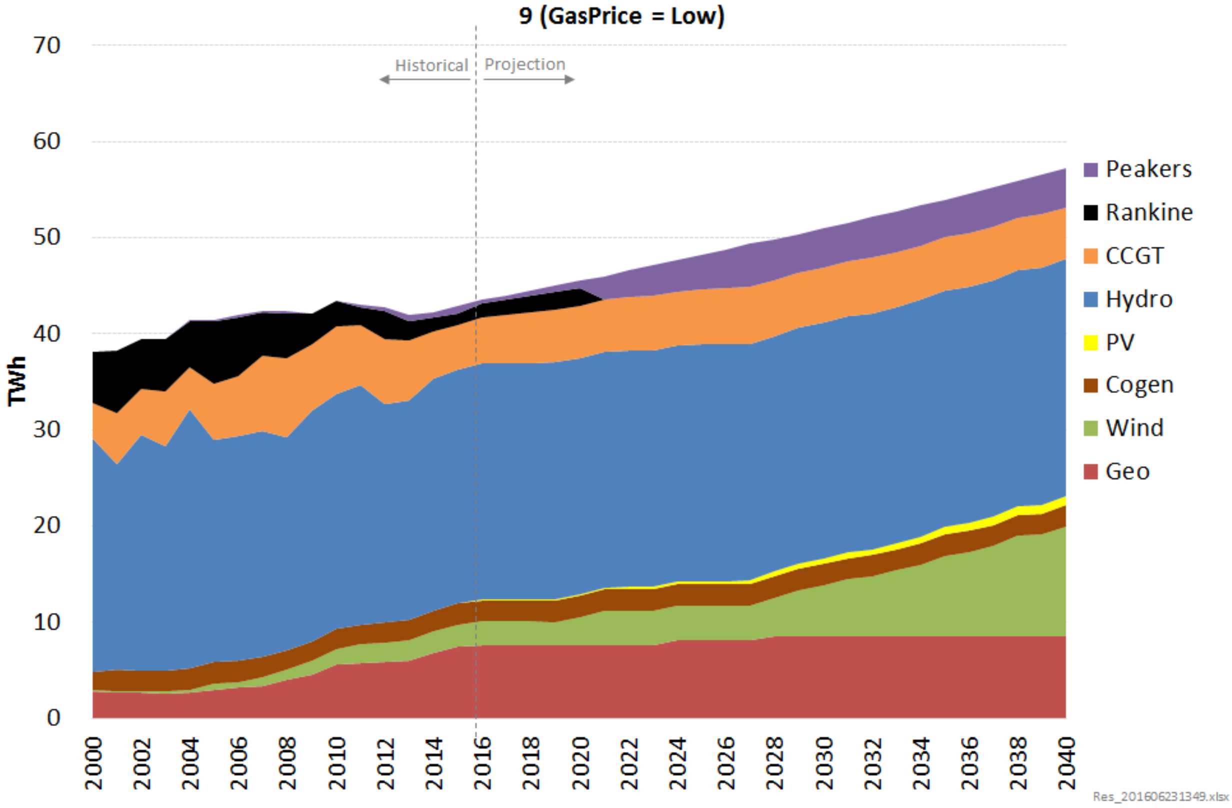
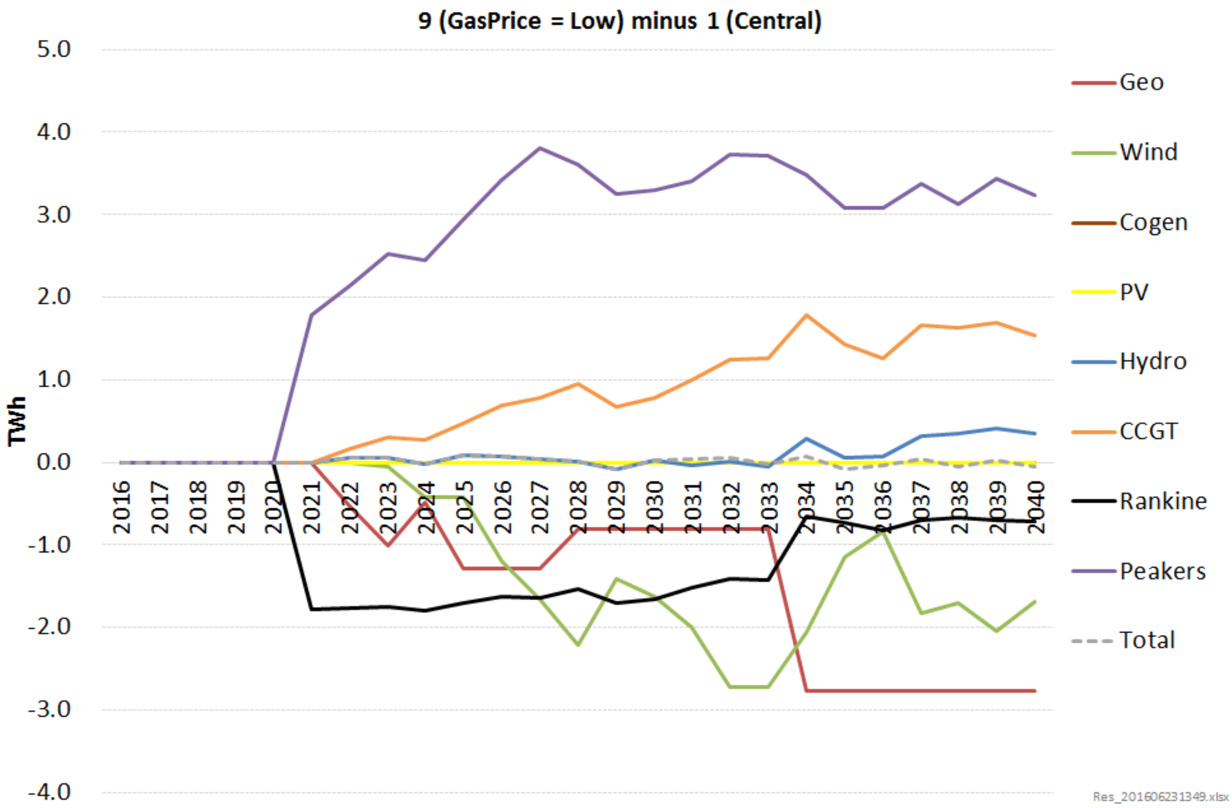


Figure 53: Comparison of power generation outcomes between a sustained low gas price scenario and the central scenario



Tight gas scenario

In a future of sustained high gas prices, a progressive scaling back of gas-fired generation relative to current levels is expected.

In particular, it is likely that the TCC and e3p CCGTs would retire, with their generation largely replaced by new renewables (with some increased spill).

However, for low capacity-factor duties (in particular to provide seasonal and dry-year duties), there is little projected change, with the Huntly Rankine units and gas-fired OCGTs projected to continue to provide such low-capacity factor generation.

Figure 54: Projected generation under a sustained high gas price scenario – area graph

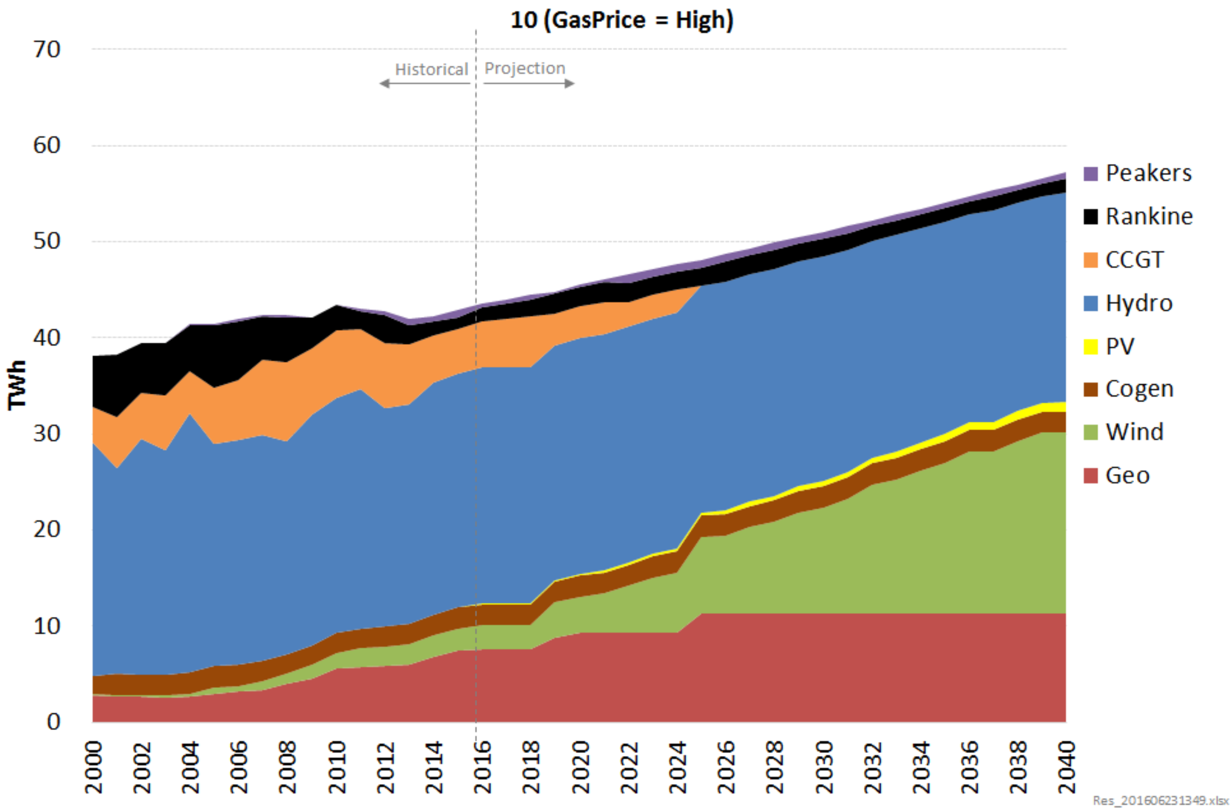
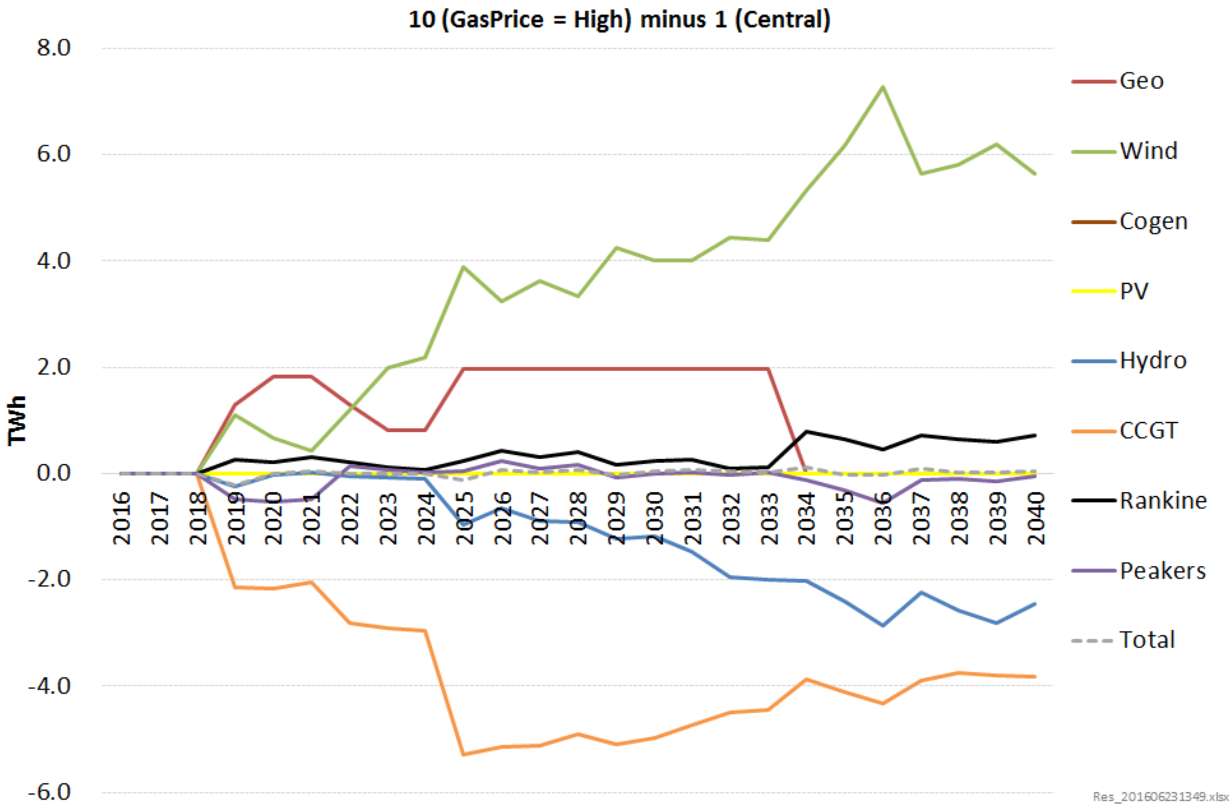


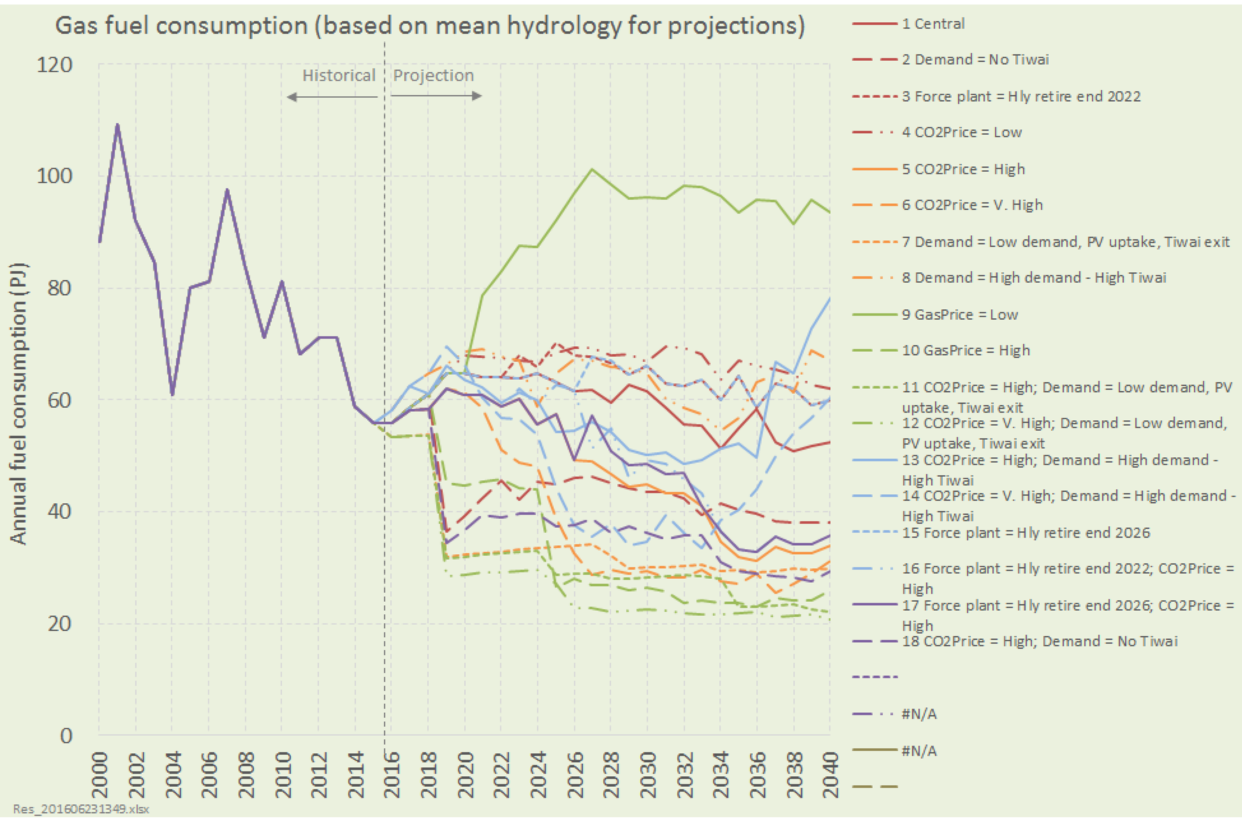
Figure 55: Comparison of power generation outcomes between a sustained high gas price scenario and the central scenario



5.4.6 Overall range of projected demand for gas for power generation

Figure 56 shows the projected gas demand across the full range of scenarios.

Figure 56:Projected gas demand for power generation under all scenarios

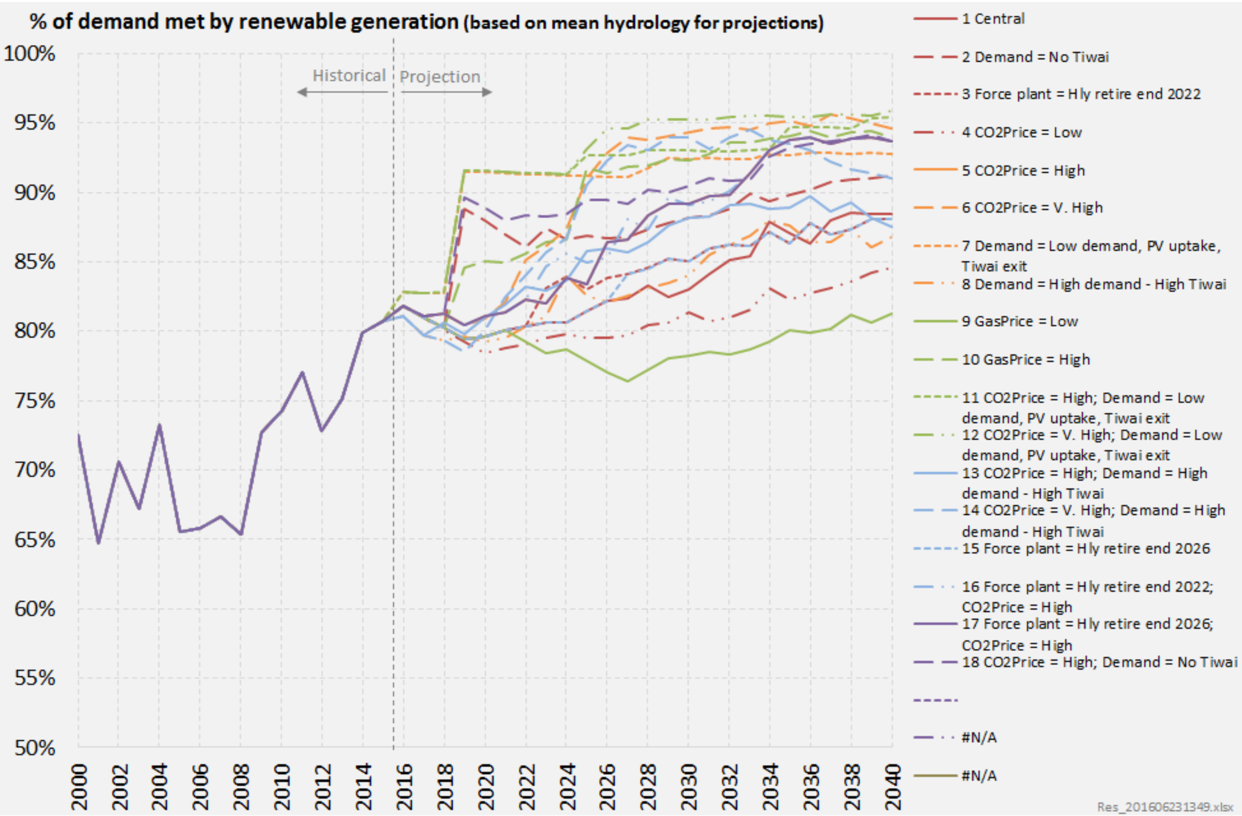


These projections reflect the range of different drivers impacting on the relative economics of renewable and fossil generation to perform the range of different duties.

As can be seen, the range of outcomes is largely bounded between 20-25 and 95 PJ of gas demand per year (for mean hydrology years). These reflect the relative economics of developing renewable and thermal plant under the different scenarios. In particular, the lower bound for gas-fired demand reflects the poor economics of developing renewables to meet lower capacity factor duties, and the inevitable spill that would occur – particularly on a dry-year/wet-year and seasonal basis.

As an aside, this dynamic will tend to create a ceiling on the proportion of electricity generation that can be economically met by renewables. This is indicated in the following graph which shows the projections of the proportion of electricity generated by renewables across the different scenarios.

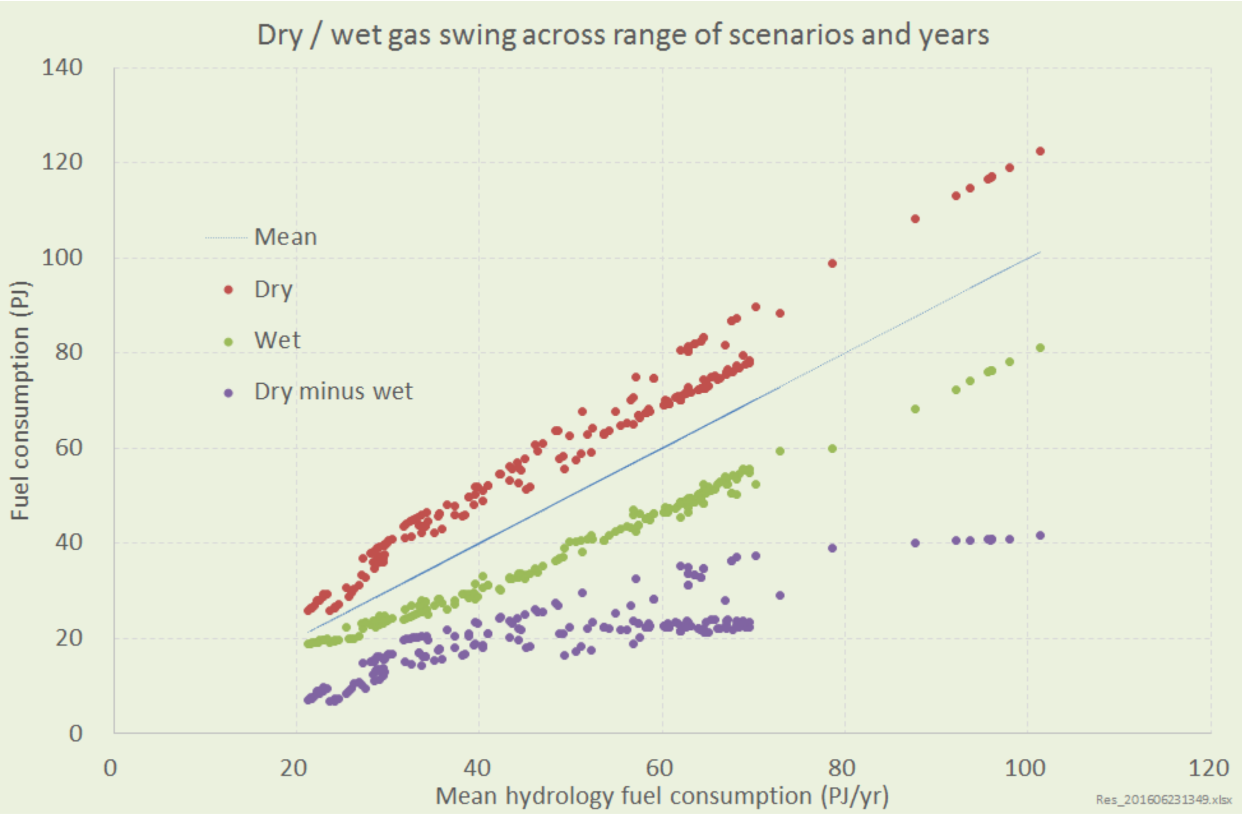
Figure 57: Projections of renewables proportions for the different scenarios



5.4.7 Effect of hydrology variation on gas demand for power generation

Much of the preceding discussion focussed on projected level of gas demand under mean hydrology. It is important to emphasise that demand for thermal fuel for power generation is strongly influenced by hydrology. We have also considered the annual demand for gas under 1-in-10 year wet and dry conditions across all the market scenarios. The results are summarised in Figure 58 across all of the sensitivity cases we have considered.

Figure 58: Projected variation in dry-year / wet-year gas swing across range of scenarios and years



Source: Concept analysis

The analysis shows that the demand for swing is strongly influenced by the level of gas demand under mean hydrology. At high levels of gas demand – predominantly relating to future scenarios where the Huntly Rankine units are retired – the annual gas swing requirement (i.e. difference between dry and wet year gas demand) is fairly constant at about 30 PJ/yr. However, at lower levels of gas demand, the demand for swing also starts to fall proportionately as well.

Although it is not apparent from the chart, the swing requirement from gas sources is materially higher in cases where the Huntly Rankine units are retired, because these remove a key source of flexible fuel from the market.

Finally, the analysis also indicates that even under quite extreme ‘low case’ assumptions of very high CO_2 prices and low electricity demand, there is a residual gas demand of around 30 PJ per year.

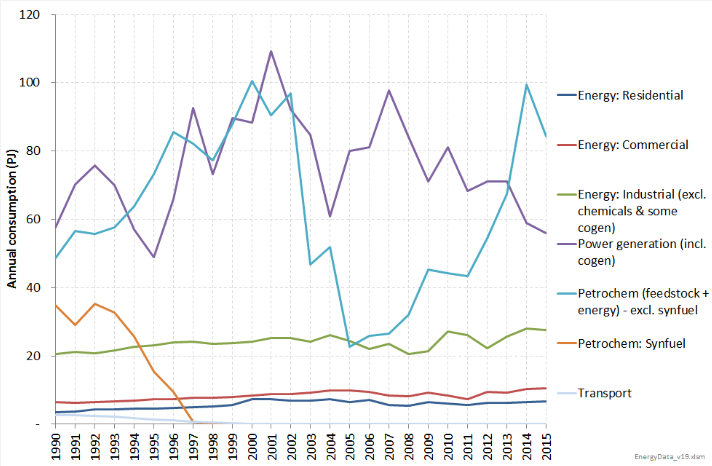
6 Direct use - industrial, commercial and residential demand

Chapter summary

The 'Direct use' segment of demand refers to gas used primarily for energy purposes – i.e. space or water heating, or to generate process heat for industrial applications – not as a feedstock for a chemical process, or a fuel for electricity generation.

Direct use of gas for energy represents the smallest segment of overall demand, accounting for approximately 24% of total New Zealand consumption in 2015. Within this segment, residential demand accounted for only 3.7% of total New Zealand consumption in 2015.

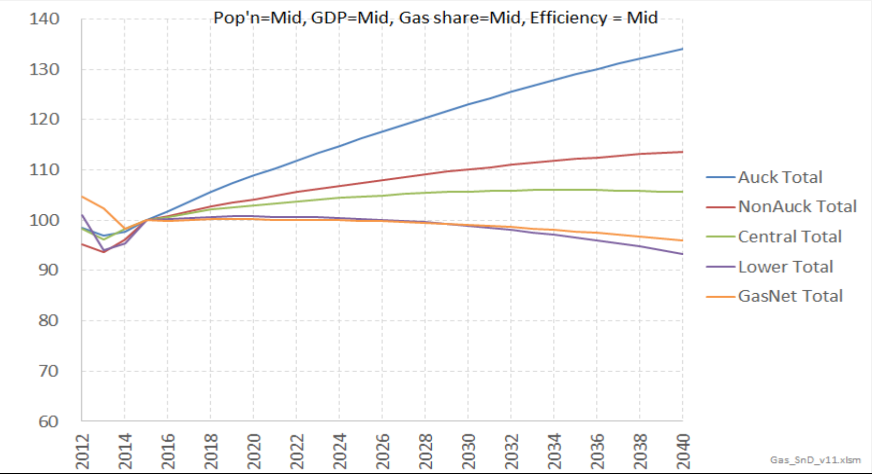
Direct use of gas for energy exhibits much less year-to-year variation in demand compared with the other uses. Thus, while the petrochemical sector has exhibited price sensitivity in terms of significantly altering consumption in response to the low-high-low wholesale gas prices seen over the last fifteen years, there has been no similar price sensitivity discernible for the direct use of gas for energy for the industrial, commercial and residential demand sectors.



The annual information disclosures made by the gas distribution network companies to the Commerce Commission have been analysed and used to project movements in demand for the five different distribution networks. Such projections sought to reflect:

- the different drivers on demand outcomes for the main uses of gas (space heating, water heating, cooking, and process heat)
- the different compositions of customer type and end-use on the four different networks
- the significant uncertainty around future projections driven by a range of factors including:
  - limited historical data
  - inherent uncertainty over the future level of key drivers of gas outcomes
  - modelling error.

The key take-away from the right graph is the significant difference in projected demand outcomes between the different networks, with much higher projected growth in Auckland compared with the Powerco Lower network.



6.1 Purpose

This chapter discusses demand for direct use of gas (i.e. industrial, commercial and residential users), and sets out future demand projections under a range of scenarios.

6.2 Historical movements in demand

The 'Direct use' segment of demand refers to gas used primarily for energy purposes – i.e. space or water heating, or to generate process heat for industrial applications – not as a feedstock for a chemical process, or a fuel for electricity generation.

This category includes over 250,000 users, covering industrial (for example meat processors), commercial (for example hotels and restaurants), and residential customers.

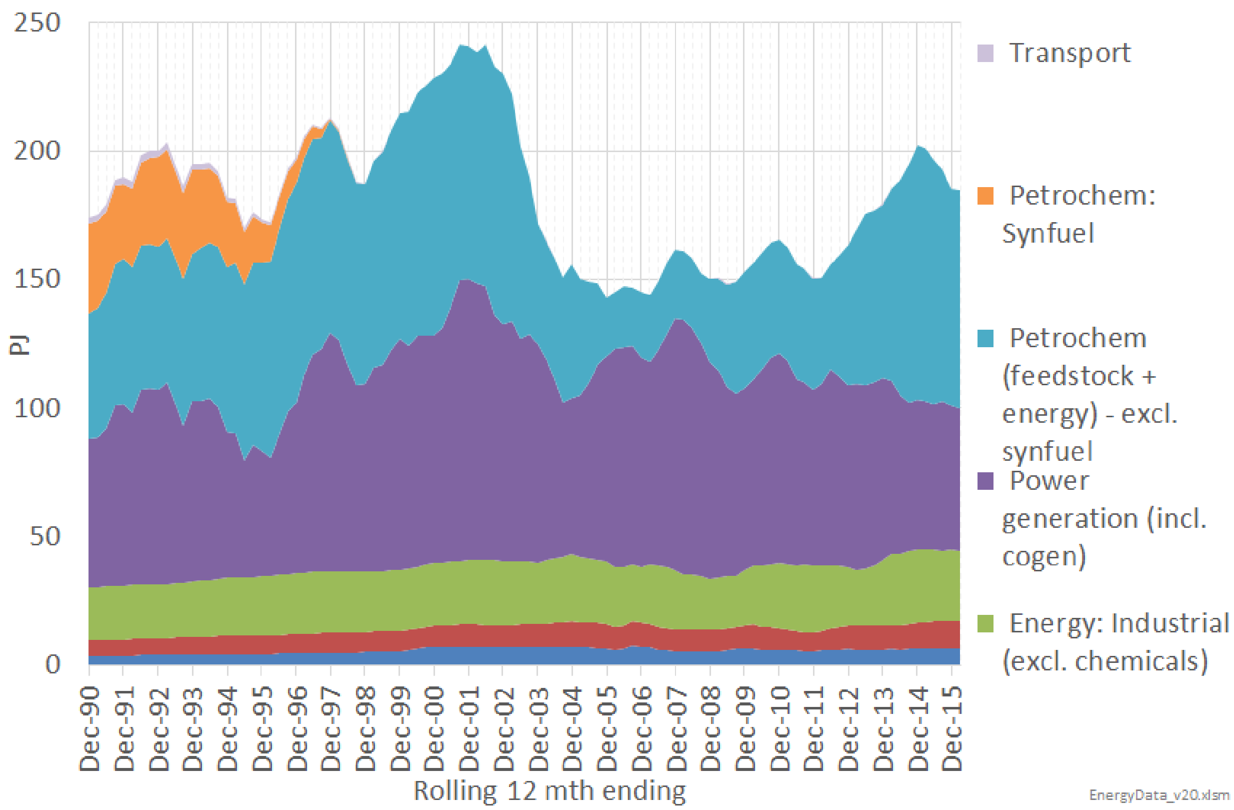
A number of different data sources have been used to analyse historical movements in gas demand for the direct use sectors.

- MBIE quarterly energy stats
- Daily Transmission gate-station data
- Distribution network disclosures made to the Commerce Commission.

6.2.1 Analysis of MBIE data

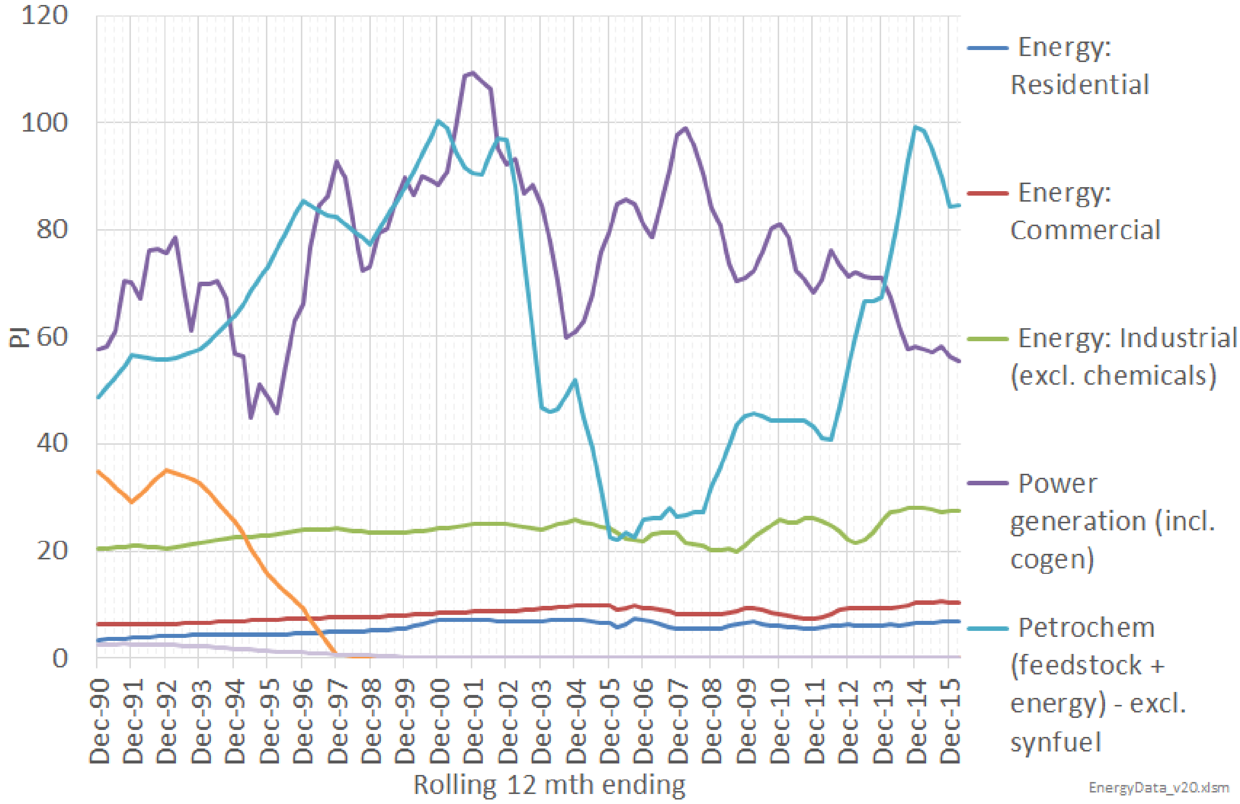
Figure 59 and Figure 60 below show how demand for the direct use for energy sectors has moved in comparison with petrochemical and power generation demand.

Figure 59: Historical sectoral gas demand - area graph



Source: Concept analysis using MBIE data

Figure 60: Historical sectoral gas demand - line graph



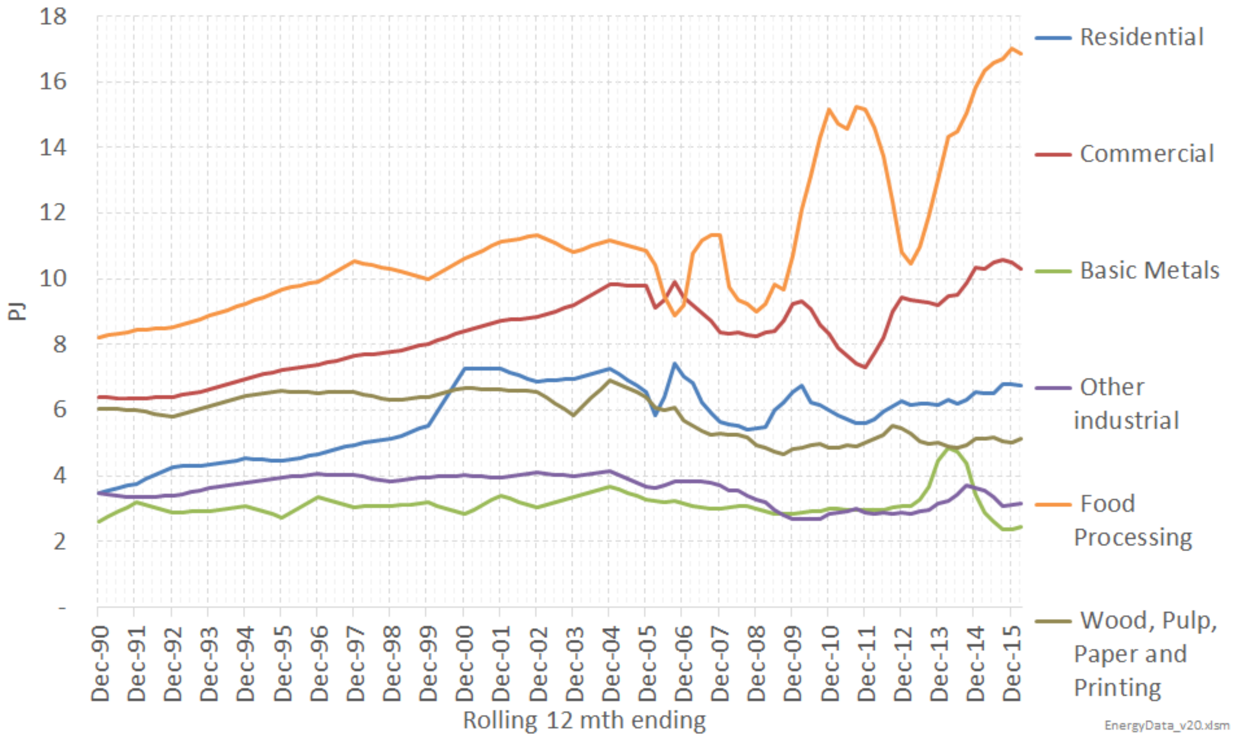
Source: Concept analysis using MBIE data

The key observations from the above figures are that:

- Direct use of gas for energy represents the smallest segment of demand, accounting for approximately 24% of total New Zealand consumption in 2015. Within this segment, residential demand accounted for only 3.7% of total New Zealand consumption in 2015.
- Direct use of gas for energy exhibits much less year-to-year variation in demand compared with the other uses. Thus, while the petrochemical sector has exhibited extreme price sensitivity in terms of significantly altering consumption in response to the low-high-low wholesale prices seen over the last fifteen years, there has been no similar price sensitivity discernible for the direct use of gas for energy for the industrial, commercial and residential demand sectors.

MBIE also provide slightly more disaggregated data, splitting the industrial category into the main sub-categories (food processing (being dairy, meat, and other food processing), forestry processing, basic metals, and other industrial). Figure 61 below show the historical movement of gas demand for these main industrial sectors (excluding chemical), plus residential and commercial.

Figure 61: Historical gas demand for industrial sectors[74]



Source: Concept analysis using MBIE data

This data relies on submissions to Statistics New Zealand by retailers who are supplying gas to consumers. This is understood to have given rise to consistency issues as consumers switch between retailers who, for statistical submissions purposes, have classified such consumers differently. For example, the apparent spike in gas consumption for food processing (largely dairy, but also meat and other food processing) in 2011 appears suspicious, particularly as it occurs at the same time as an apparent drop in commercial consumption.

Nonetheless it is a reasonable gauge of general trends, which indicate:

- Strong growth in the food processing sector. This is understood to be particularly from the dairy processing sector
- A slight decline in the forestry processing sector. This is understood to be largely due to fuel substitution away from gas to on-site biomass (and in some cases geothermal).
- Flat (indeed slightly declining) demand for the basic metals and other industrial sectors
- Steadily increasing demand for the commercial sector
- Flat demand for the residential sector from about 2000, following a period of steady growth

These trends are indicative of the overall nature of the New Zealand economy:

- Continued growth in the primary agricultural sector, particularly dairy
- Other economic growth being predominantly in the commercial sector, rather than the more energy-intensive industrial / manufacturing sectors.

[74] It should be noted that a significant amount of gas demand for the Basic metals and Food processing sectors is for major cogeneration plants in the Steel (for the Glenbrook cogeneration plant) and Dairy (for the Te Rapa cogeneration plant in particular) sectors, respectively. However, this demand is not included in this figure.

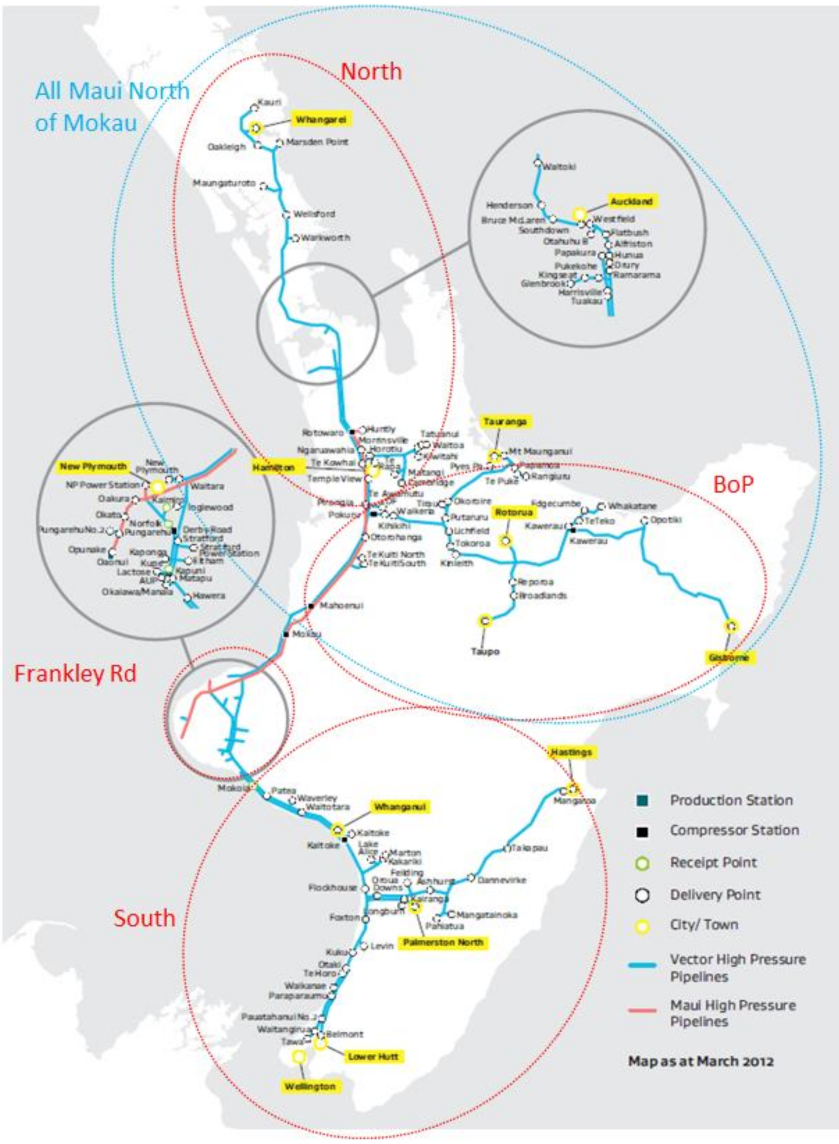
- The significant effect of energy efficiency on residential demand in particular, coupled with the emergence of a key competing alternative technology (namely heat pumps) that is understood to be impacting on gas market share in the residential space.

6.2.2 Analysis of transmission pipeline gate-station data

Daily gate station data published on the open access transmission information system (OATIS) was analysed, and grouped according to:

- Geographic zones, as per Figure 62.[75]
- Customer type, based on assignment of transmission-connected customers to particular industrial segments. For distribution network connections, the demand was split between 'ToU' and 'Non'-TOU segments using the GAR170 report produced by GIC for gas allocation purposes.

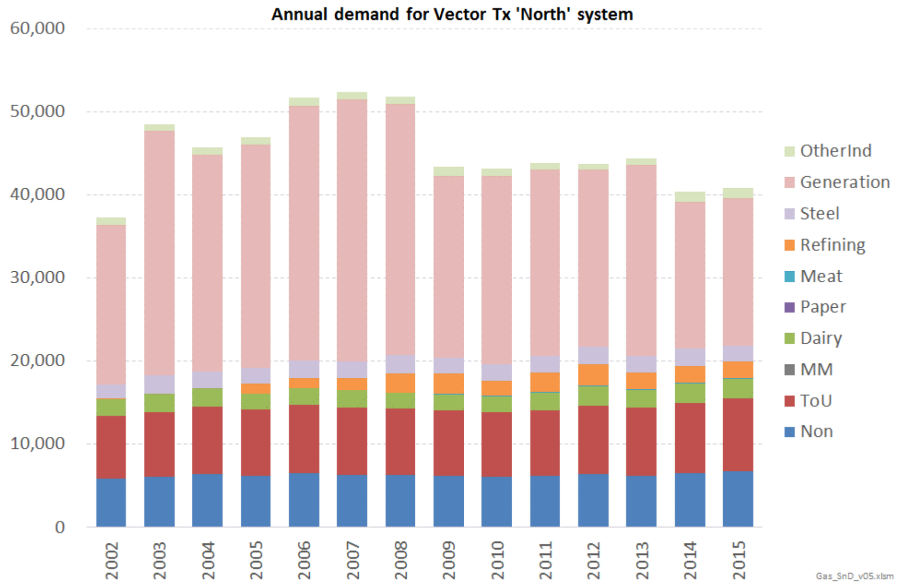
Figure 62: Transmission region groupings for Tx gate station analysis

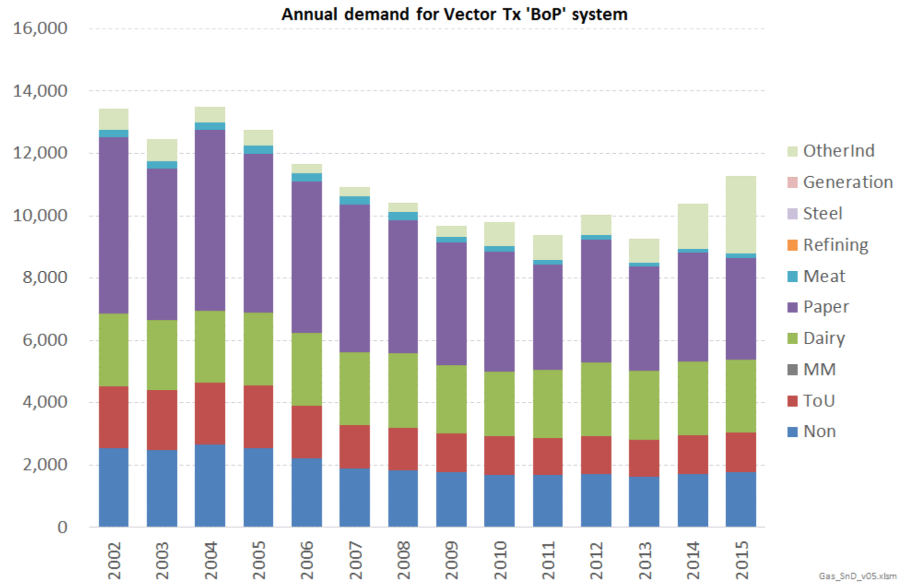


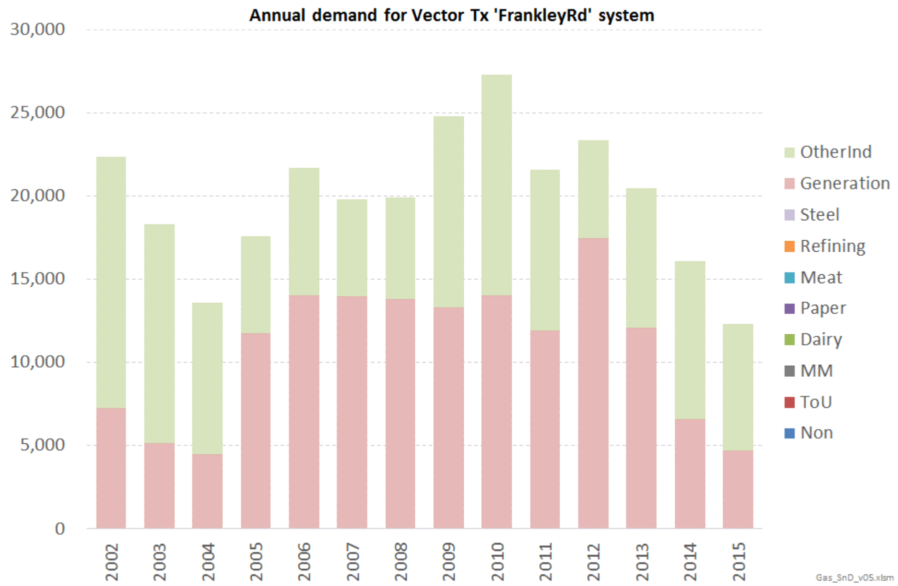
The results of the analysis are shown in the graphs on the following pages.

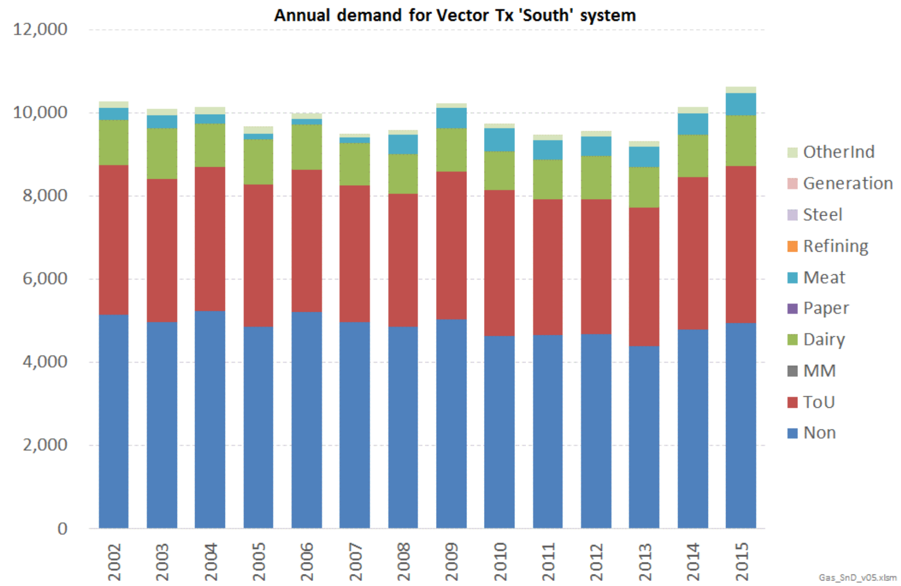
---

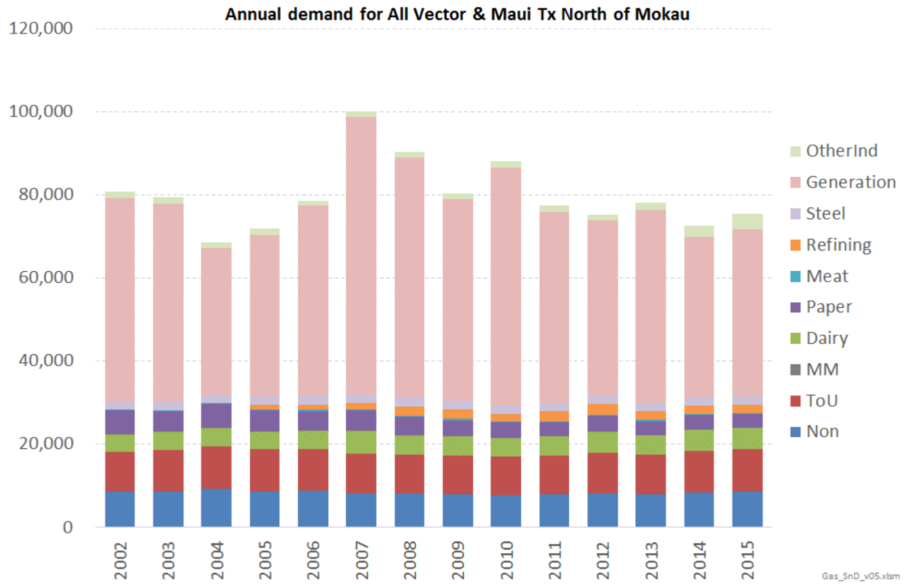
[75] The 2014 study had separate zones for 'Central North' and 'Central South'. For this 2016 study these have been grouped into the 'North' and 'BoP' zones respectively. This reflects the limited additional value such geographical sub-division delivered relative to the overhead in terms of analysis, particularly seeing as the retirement of the two main North region power stations has meant that network capacity analysis is no longer a focus of this study.

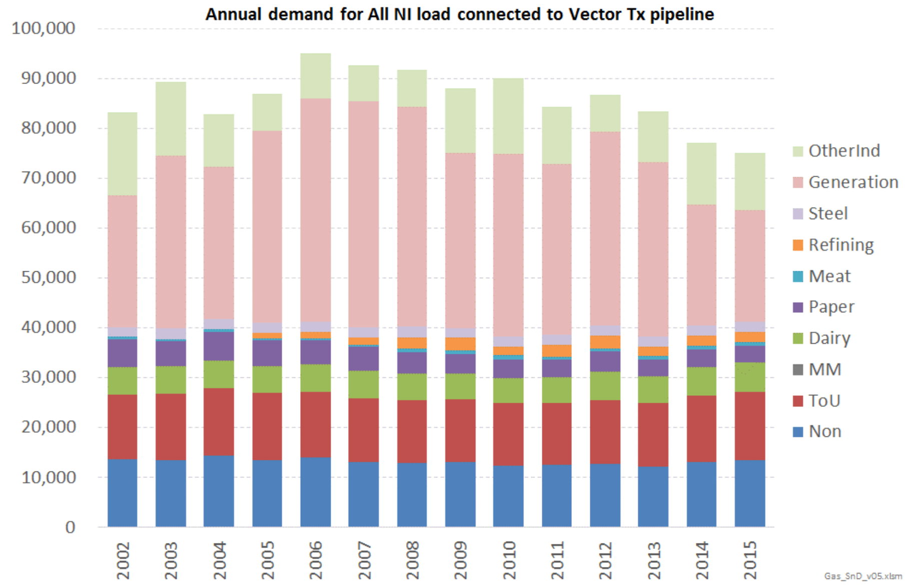

Annual demand for Vector Tx 'North' system
60,000
50,000
40,000
30,000
20,000
10,000
0
2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015
OtherInd
Generation
Steel
Refining
Meat
Paper
Dairy
MM
ToU
Non
Gas_SnD_v05.xlsm

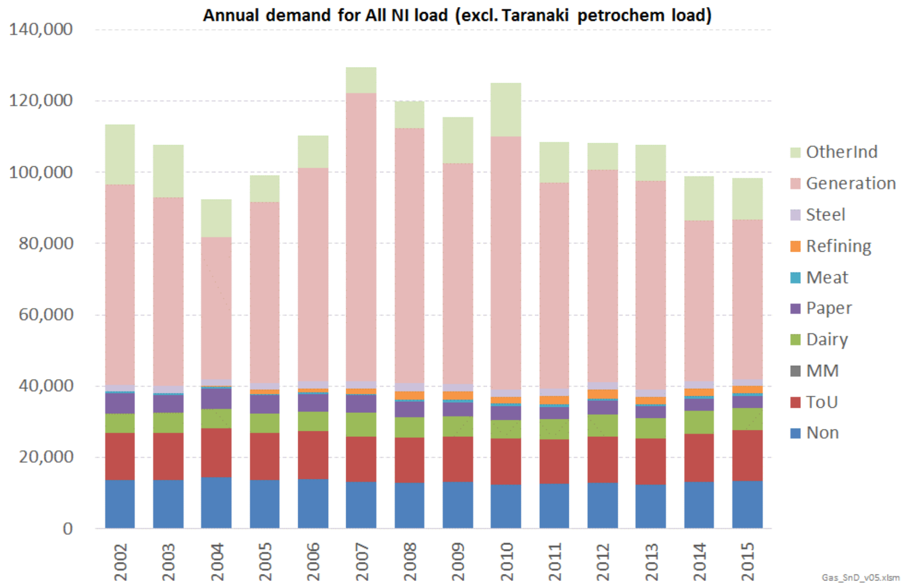

Annual demand for Vector Tx 'BoP' system
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015
OtherInd
Generation
Steel
Refining
Meat
Paper
Dairy
MM
ToU
Non
Gas_SnD_v05.xlsm


Annual demand for Vector Tx 'FrankleyRd' system
30,000
25,000
20,000
15,000
10,000
5,000
0
2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015
OtherInd
Generation
Steel
Refining
Meat
Paper
Dairy
MM
ToU
Non
Gas_SnD_v05.xlsm


Annual demand for Vector Tx 'South' system
12,000
10,000
8,000
6,000
4,000
2,000
0
2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015
OtherInd
Generation
Steel
Refining
Meat
Paper
Dairy
MM
ToU
Non
Gas_SnD_v05.xlsm


Annual demand for All Vector & Maui Tx North of Mokau
120,000
100,000
80,000
60,000
40,000
20,000
0
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
OtherInd
Generation
Steel
Refining
Meat
Paper
Dairy
MM
ToU
Non
Gas_SnD_v05.xlsm


Annual demand for All NI load connected to Vector Tx pipeline
100,000
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
OtherInd
Generation
Steel
Refining
Meat
Paper
Dairy
MM
ToU
Non
Gas_SnD_v05.xlsm


Annual demand for All NI load (excl. Taranaki petrochem load)
140,000
120,000
100,000
80,000
60,000
40,000
20,000
0
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
OtherInd
Generation
Steel
Refining
Meat
Paper
Dairy
MM
ToU
Non
Gas_SnD_v05.xlsm

These historical graphs show that the demand composition on the different transmission pipelines is very different. This has also resulted in quite different movements in demand over this historical period and, as is analysed further in section 6.3, will likely result in material differences in future demand growth for these different transmission regions.

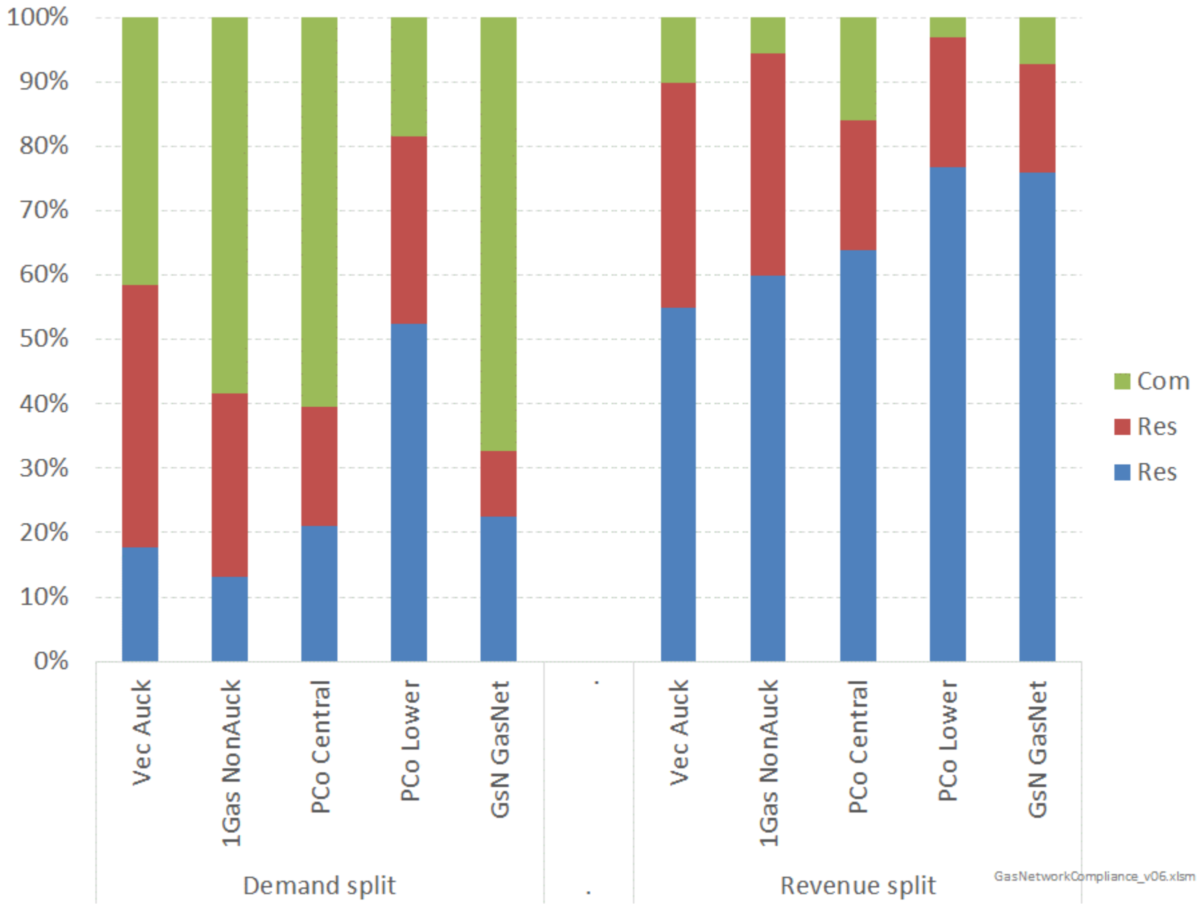
6.2.3 Analysis of Commerce Commission disclosures

For this latest Supply / Demand study, a further new source of data has been analysed – the annual information disclosures made by the gas distribution network companies to the Commerce Commission.

The purpose of performing such analysis is because the Commerce Commission has indicated a desire to potentially use the projections developed for this GIC Supply / Demand exercise as an input into its Constant Price Revenue Forecasting process for the next regulatory control period.

The other two data sets (MBIE data, and Transmission gate station data) do not provide sufficiently disaggregated information on the different customer compositions of the different networks in order to produce projections that would be appropriate at a distribution network level.[76] Accordingly, the Commerce Commission disclosures were used as they provide greater disaggregation, as indicated by Figure 63.

Figure 63: Reported FY15 demand and revenue splits for different consumer segments for different distribution networks



Source: Concept analysis of Commerce Commission information disclosures

These disclosures were analysed for the five main reported distribution networks: Vector Auckland, Vector Non-Auckland (now First Gas), Powerco Central, Powerco Lower, and GasNet.

[76] Although the transmission gate station data in combination with the GAR170 can deliver a breakdown between ToU and non-TOU load, there is no indication of the split between residential, commercial and industrial load.

The disclosures were made by the network companies disaggregated by load groups. These load groups were assigned for this analysis into three main customer segments: Residential, Commercial and Industrial. The assignment of a load group into segments was largely based on the network companies' own classification on such a basis.

Appendix C provides the detailed analysis of historical distribution network outcomes over the four years of data. The analysis indicates there were some material changes in demand over this four-year period, but in many cases there is no consistent trend over time:

- Across different customer segments (i.e. Res, Com, Ind);
- Within individual networks

The analysis also indicates that it is likely that there has been some re-classification of load groups between FY13 and FY14 in the two Vector-owned networks (noting that 1Gas NonAuck was owned by Vector until recently), and that this re-classification will have resulted in non-consistent classification of customers into the "Com" and "Ind" customer segments.

6.3 Projections of demand

This sub-section first details the distribution-network projections, before then describing the broader transmission-level projections.

6.3.1 Distribution network projections

Appendix C sets out the detailed approach used to project movements in demand for the four different distribution networks. Such projections sought to reflect:

- the different drivers on demand outcomes for the main uses of gas (space heating, water heating, cooking, and process heat)
- the different compositions of customer type and end-use on the four different networks
- the significant uncertainty around future projections driven by a range of factors including:
  - limited historical data
  - inherent uncertainty over the future level of key drivers of gas outcomes
  - modelling error.

The following graphs show the projected central-scenario gas demands for the four different network areas, both in absolute terms, and in terms of relative annual movement.

Figure 64: Central projections of annual quantities of gas (TJ). (≤2015 are actuals)

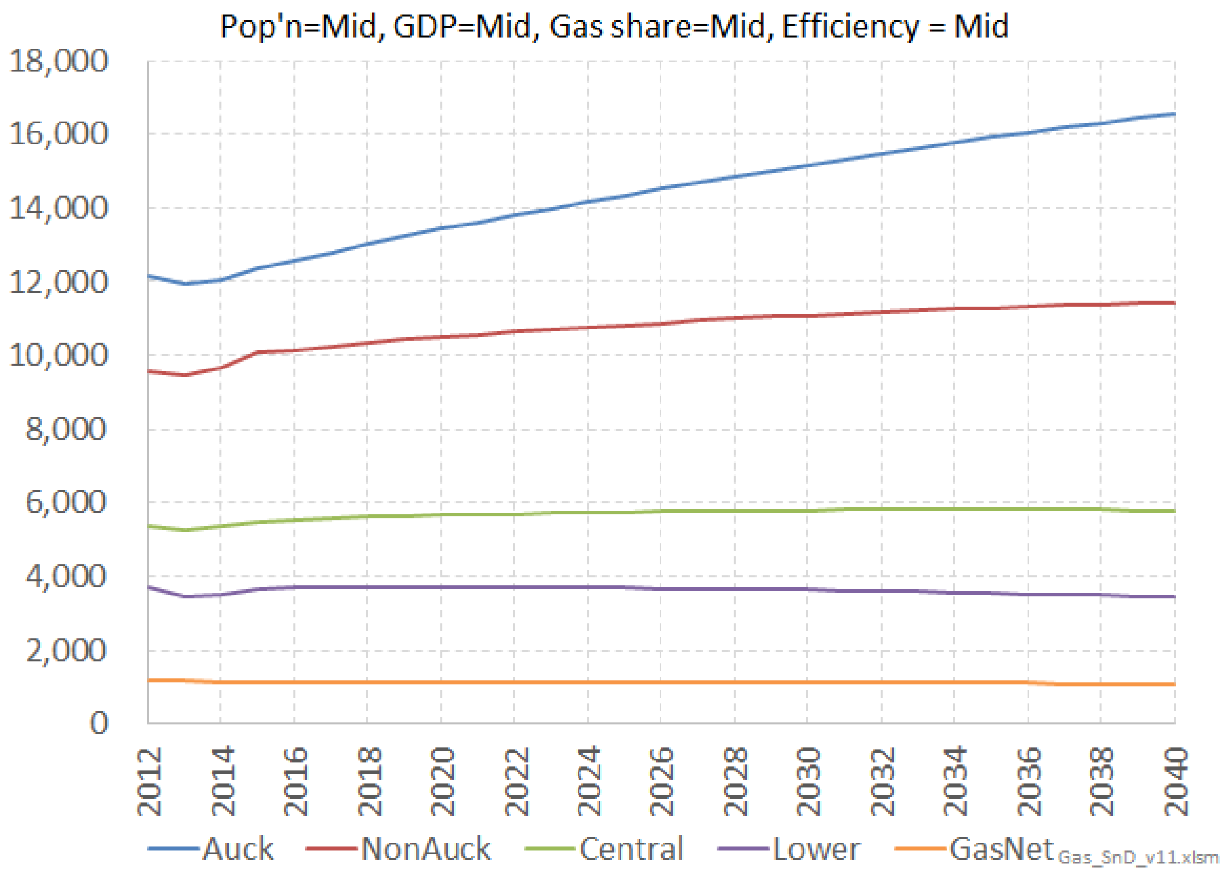
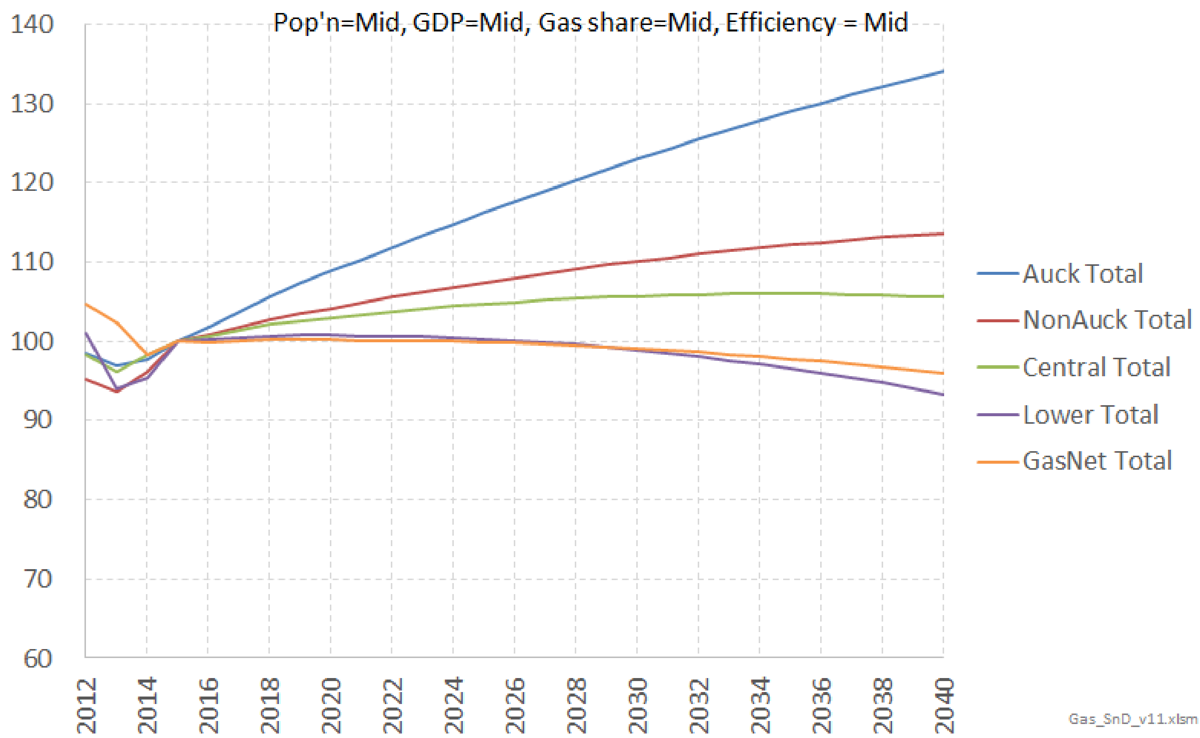


Figure 65: Central projections of relative change in annual quantities of gas (≤2015 are actuals)

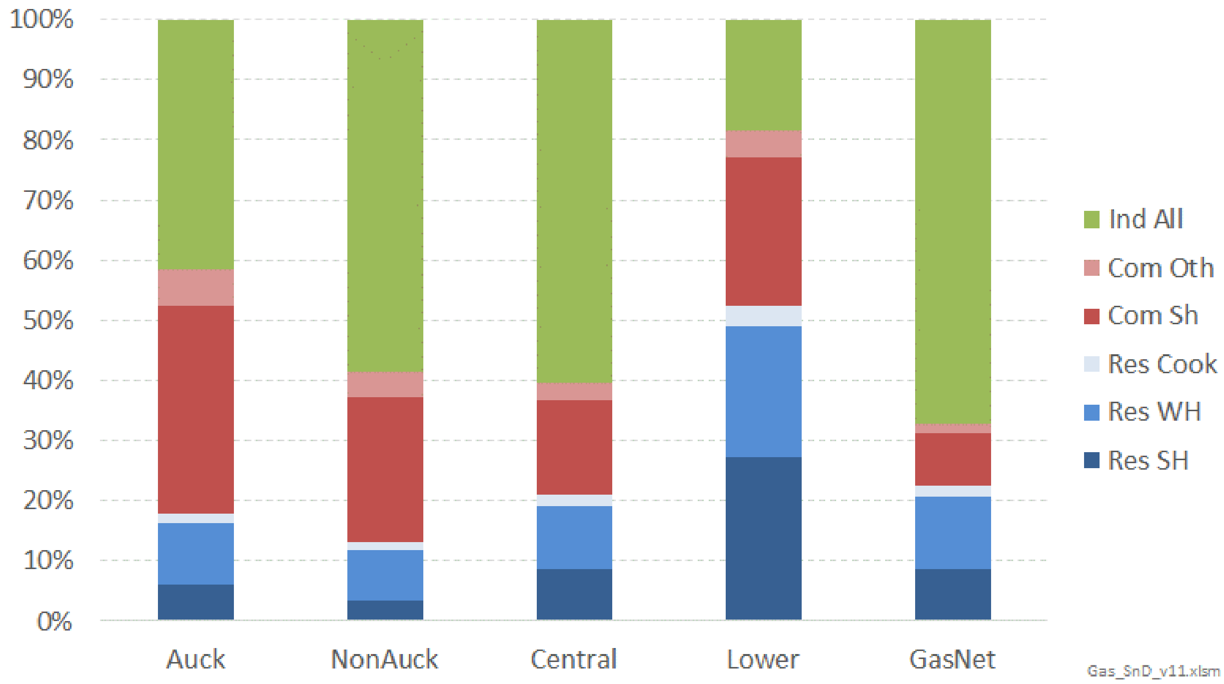


The key take-away from the above graphs is the significant difference in projected demand outcomes between the different networks, with much higher projected growth in Auckland compared with the slight long-term decline in the Powerco Lower network.

This difference is principally a function of the following factors:

- Much higher projected population and GDP-related growth in Auckland than in these other networks.
- The different estimated proportions of customer types and end uses, as shown in Figure 66 below. This is significant because, as is further illustrated in Figure 67, the different types of customer and end-use are projected to have material differences in the success of winning fuel market share from electricity and other fuel options (e.g. wood or LPG). As is detailed in Appendix C, this projected relative success is based on analysis undertaken for the recent Consumer Energy Options study[77], combined with other analysis of the relative market shares of gas compared with other fuels for these different consumer end-uses.

Figure 66: Estimated break-down of FY15 demand into key end-use segments by network area



[77] The Consumer Energy Options report and associated stakeholder presentation is available here: http://gasindustry.co.nz/about-us/news-and-events/events/release-of-consumer-energy-options-in-new-zealand-2016-update-by-simon-coates/

Figure 67: Projected relative change in demand for gas for the key end-use segments

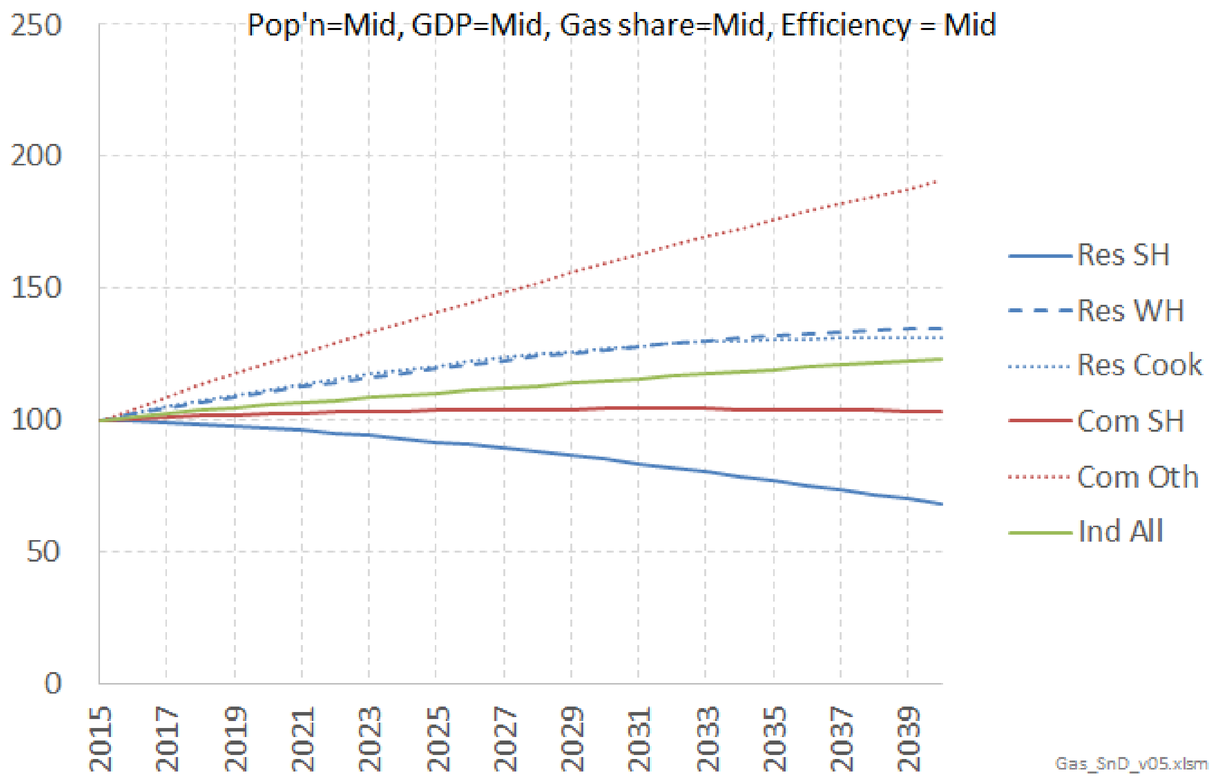
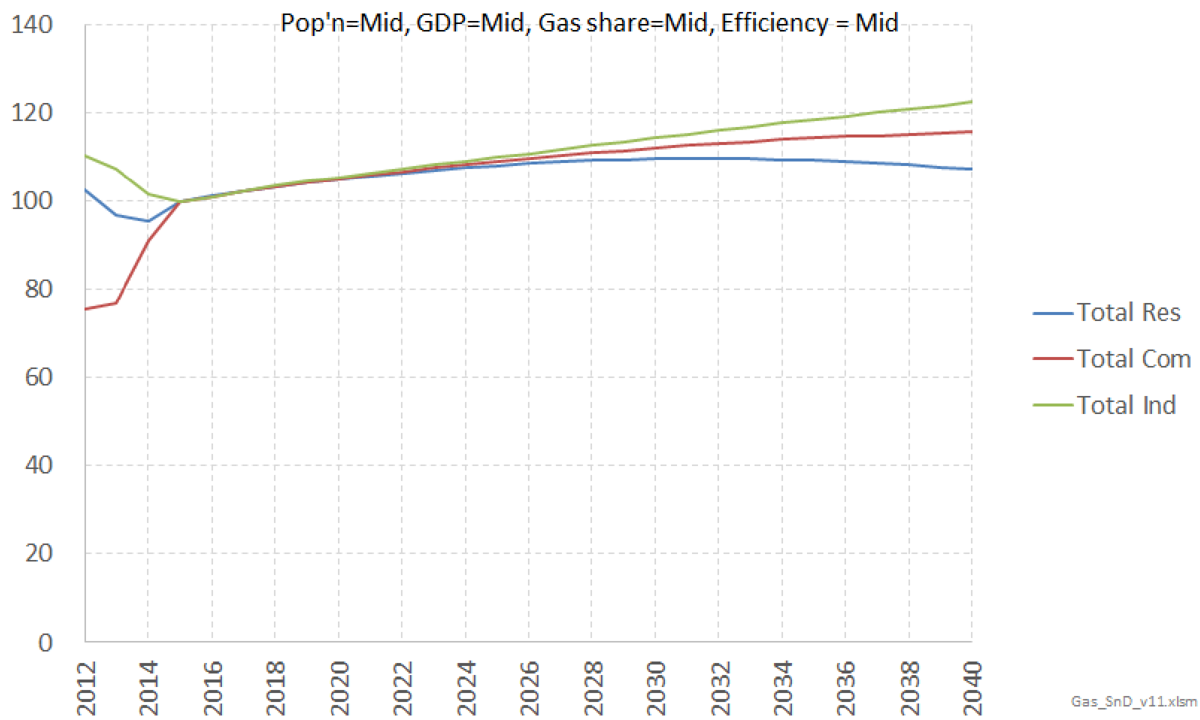


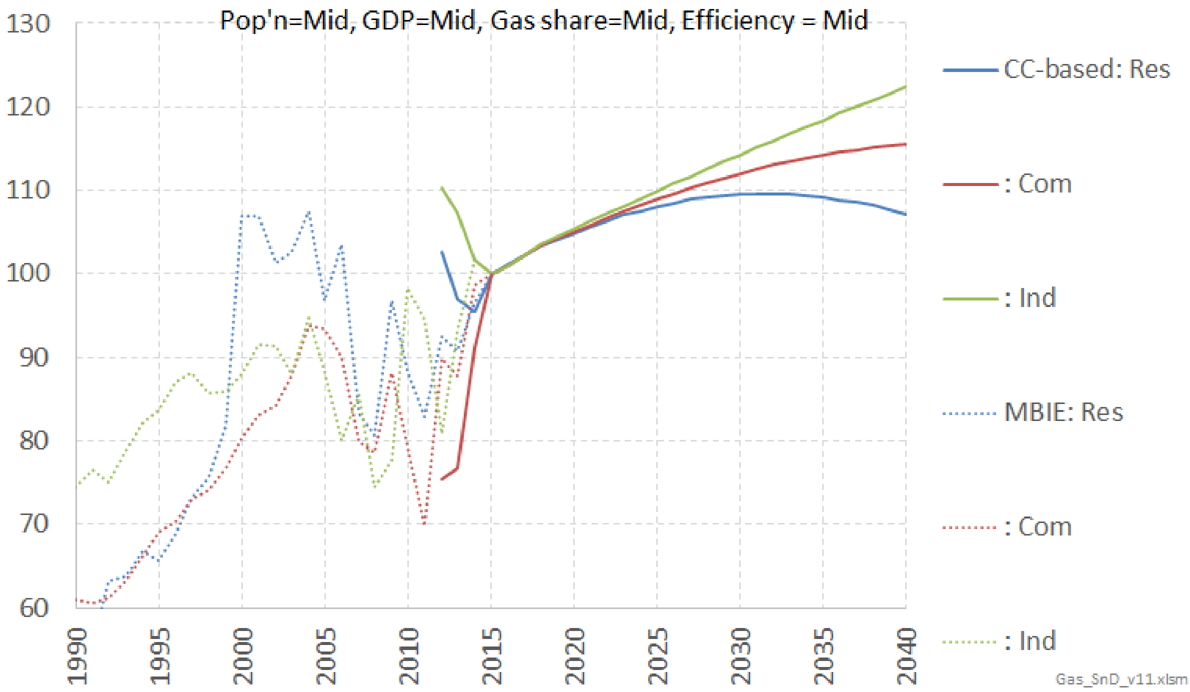
Figure 68: Central projections of relative movement in Residential, Commercial, and Industrial demand summed across all networks



Comparison with historical data series and projections

Further analysis was undertaken to compare the projected overall movement in residential commercial and industrial demand shown in Figure 68, with historical changes in Residential, Commercial, and Industrial demand over a longer time series as reported by MBIE. This is shown in Figure 69.

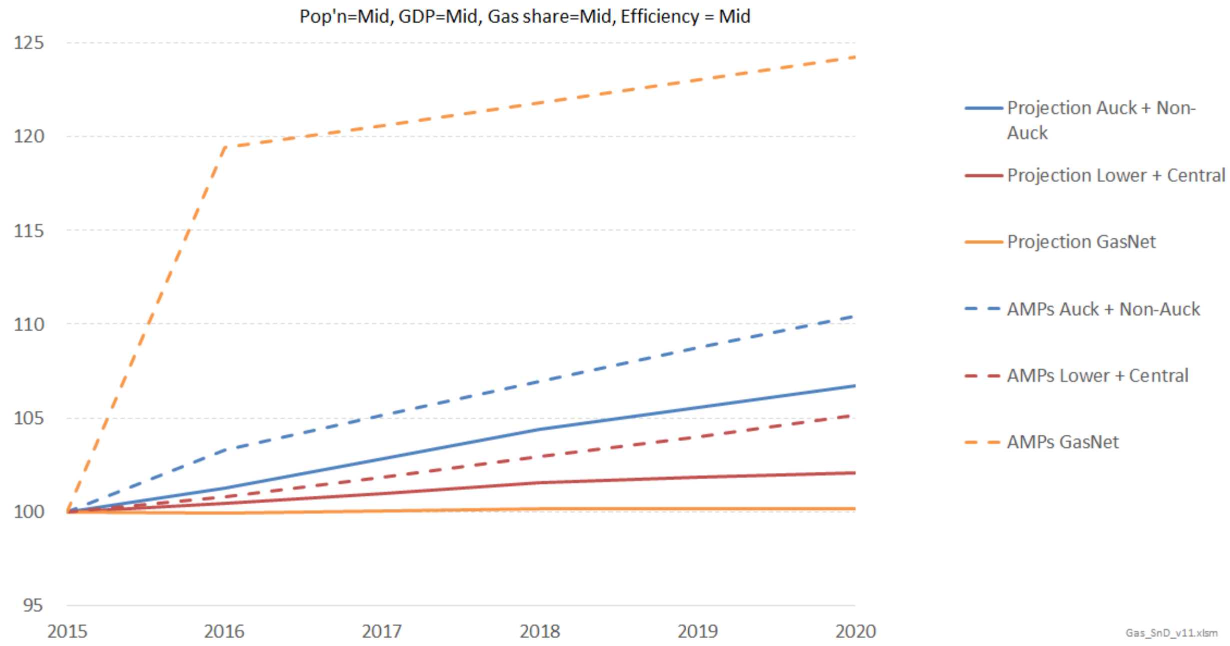
Figure 69: Comparison between historical MBIE-reported change in gas demand for different customer segments with projected change in demand



Lastly, comparison was made with the demand projections made in the most recent distribution network asset management plans produced by Vector, Powerco and GasNet. These are not disaggregated by sub-network for Vector and Powerco (e.g. Auck/Non Auck, Central/Lower) or by customer type. The results are shown in Figure ***110***. They appear to indicate that the network companies expect greater demand growth than projected by Concept. Further, the extent to which Concept is 'under-estimating' appears to be consistent between the Vector, Powerco and GasNet. GasNet is projecting a significant one-off increase in demand between 2015 and 2016. This may be due to a large one-off industrial connection.

This may indicate that Concept's projections are under-estimating the likely growth of gas for the different networks. However, no analysis has been undertaken to understand the underlying factors driving the differences between Concept's projections and the network companies' own projections.

Figure 70 Comparison between Concept central-scenario projections of gas demand growth and network companies' AMP projections



Appendix C also presents analysis indicating that these projections are subject to a significant margin of uncertainty, given inherent uncertainties over future values for many key input parameters, as well as uncertainty due to lack of historical data and modelling error.

6.3.2 Transmission network projections

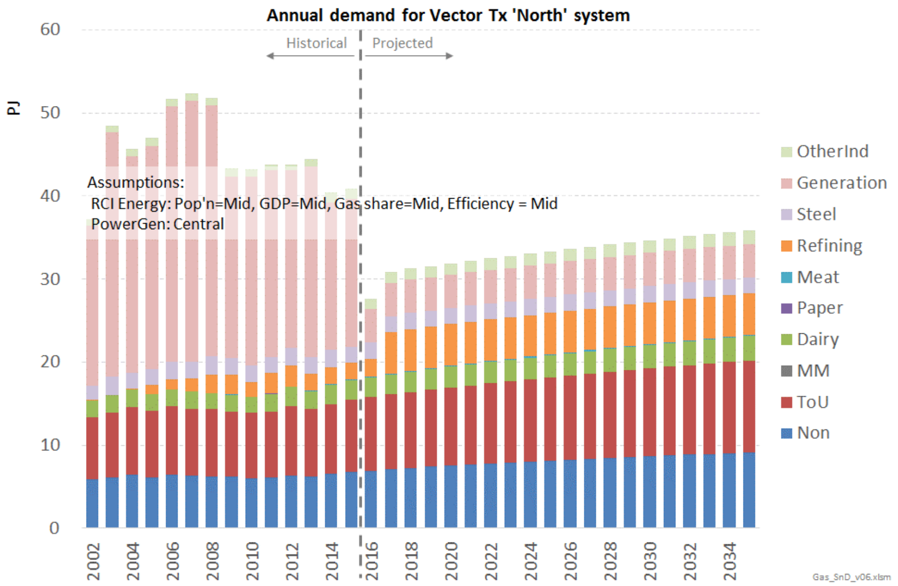
The model has also been configured to allow projections for the transmission regions detailed on page 90. For the Non, ToU and most of the other industrial segments, the projections are driven from the detailed distribution network projections set out above. The exceptions to this are:

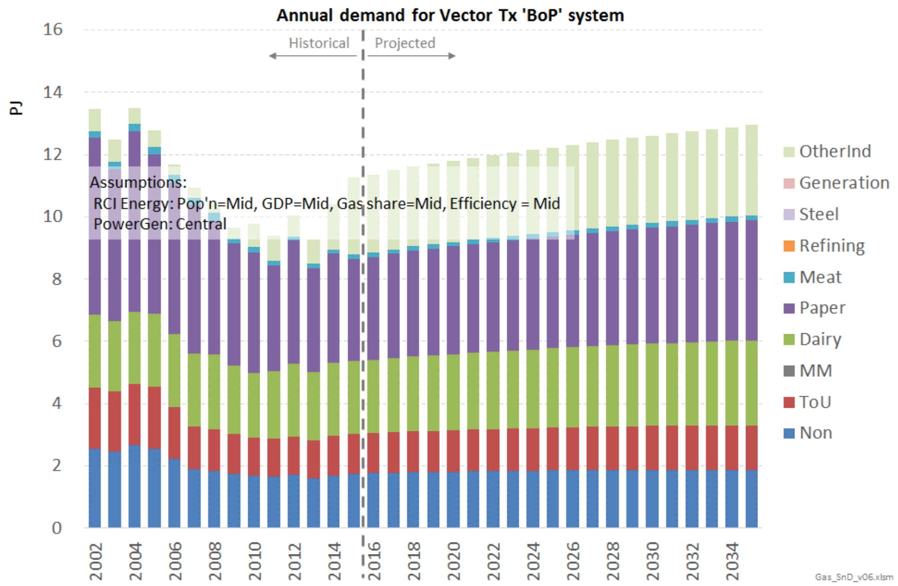
- Generation, where the projections from the detailed power system modelling described in section 5.4 are used.
- Refinery, where an explicit projection is developed which takes account of the planned significant expansion of the refinery in 2017.
- Steel, where a flat demand projection is assumed, but with an ability to specify a possible closure of the Glenbrook steel mill at a user-specified date. This sensitivity has been enabled because of the challenging economic conditions facing the steel mill, given the overcapacity in world steel production.

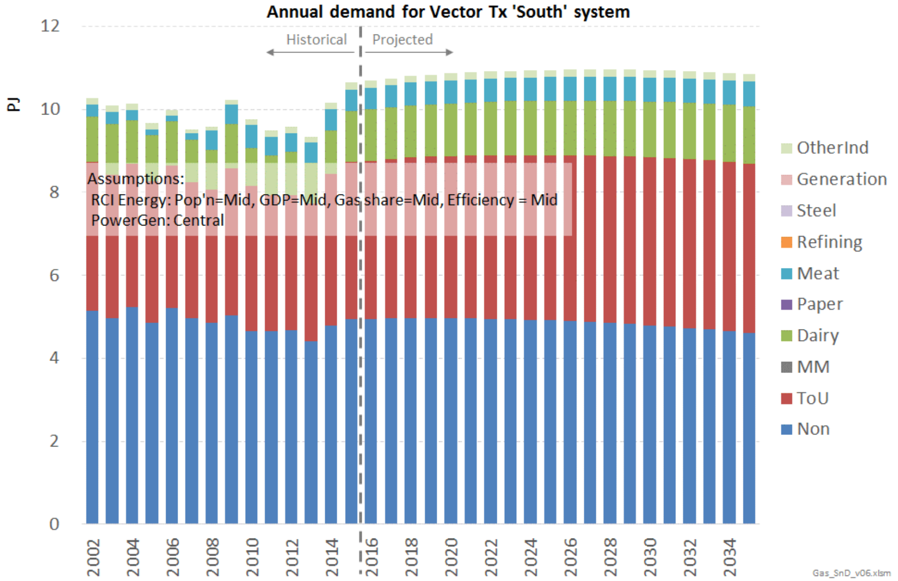
The central-case projections for the main transmission regions are shown in the graphs on the following pages. In addition to projections of annual demand, projections of peak week demand are also shown. These have been developed using a fairly high-level approach, which projects each customer segment's potential peak week demand using the observed historical ratios between annual demand and each segment's contribution to peak week demand. It should be appreciated that this is a fairly basic approach to projecting peak network demands.

This approach is used because the closure of the two North system power stations (Otahuhu B and Southdown) can be seen to significantly reduce peak demand requirements on the North and Maui-north of-Mokau transmission systems. These two systems were the only ones identified in previous studies as having the potential for material transmission constraints at this whole-of-system level which may require investment (e.g. looping north of Rotokawa to relieve the North system constraint, or a compressor upgrade at Mokau). With the closure of the two power stations, there is no longer a focus on system-level transmission constraints. That is not to say that there may not be within-system transmission constraints on a sub-system level (e.g. the transmission system north of Auckland). However, consideration of such detailed network constraints was out of scope for this exercise.

Figure 71: Projected central-case annual demand for different transmisison regions






Annual demand for Vector Tx 'South' system
Historical
Projected
PJ
Assumptions:
RCI Energy: Pop'n=Mid, GDP=Mid, Gas share=Mid, Efficiency = Mid
PowerGen: Central
OtherInd
Generation
Steel
Refining
Meat
Paper
Dairy
MM
ToU
Non
Gas_SnD_v06.xlsm

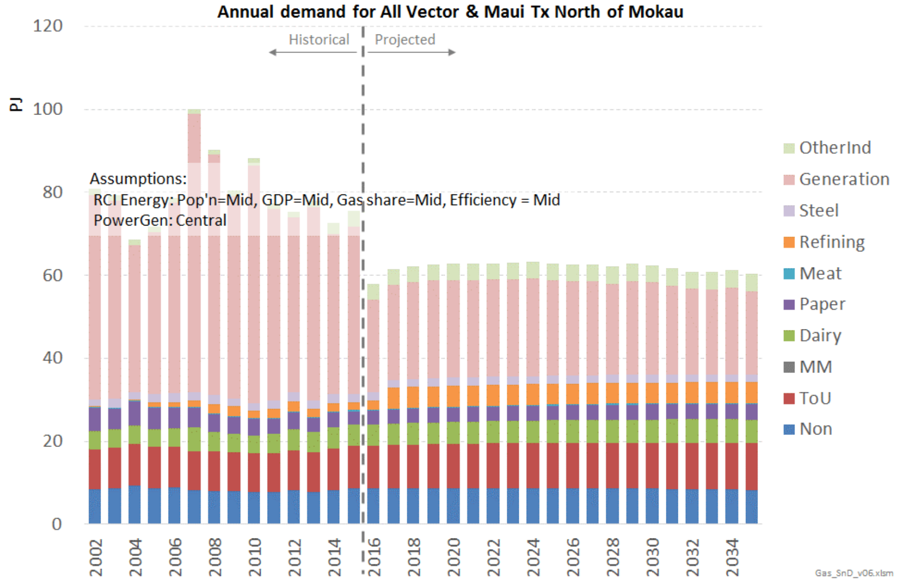
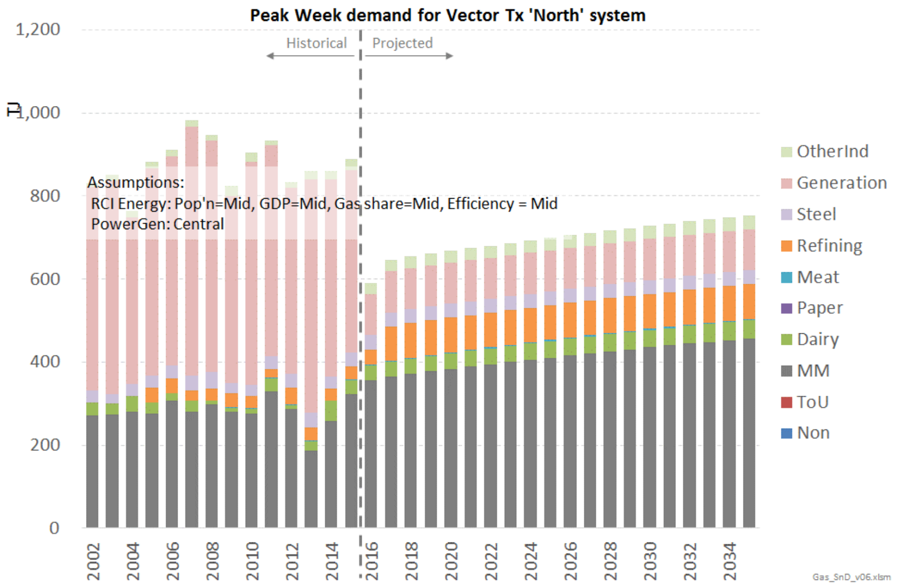
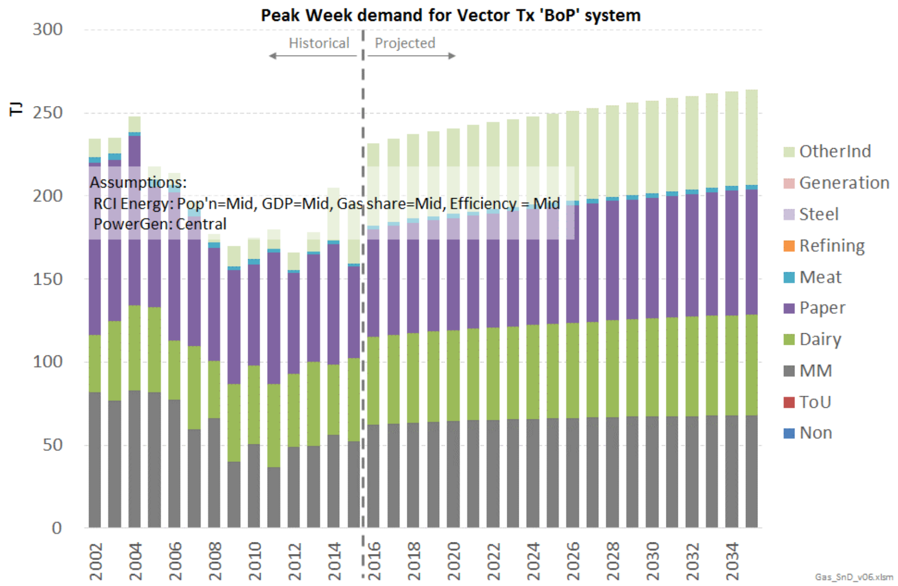
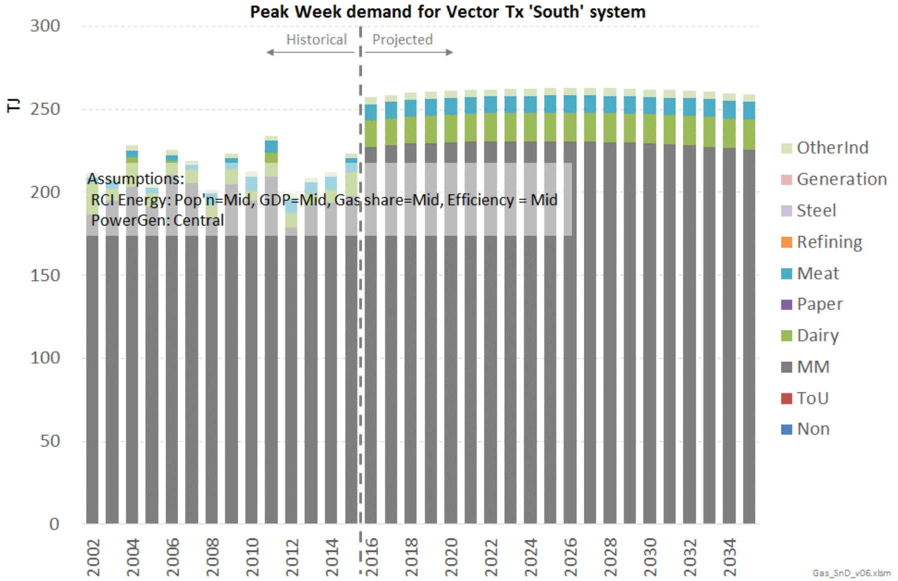

Annual demand for All Vector & Maui Tx North of Mokau
Historical
Projected
PJ
Assumptions:
RCI Energy: Pop'n=Mid, GDP=Mid, Gas share=Mid, Efficiency = Mid
PowerGen: Central
OtherInd
Generation
Steel
Refining
Meat
Paper
Dairy
MM
ToU
Non
Gas_SnD_v06.xlsm

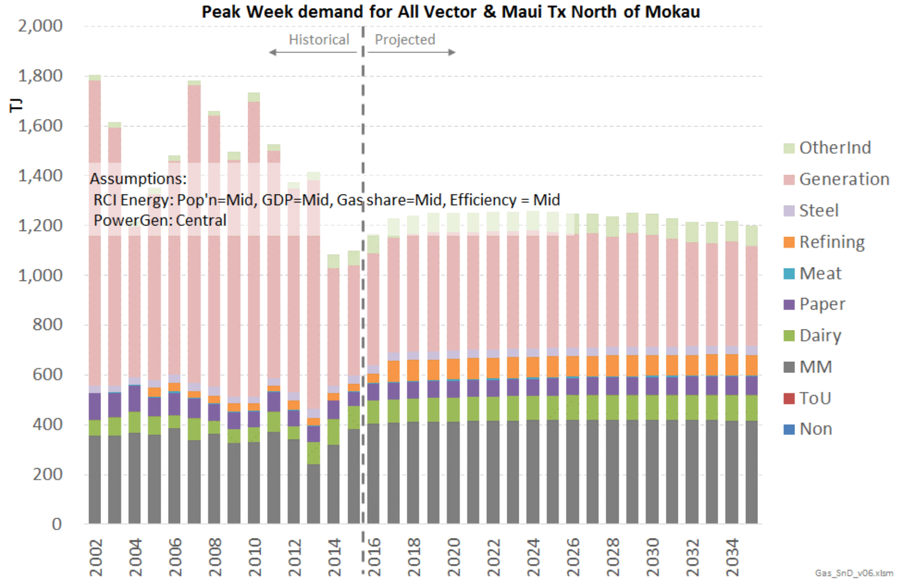
Figure 72: Projected central-case prudent peak week demand for different transmission regions







Peak Week demand for Vector Tx 'South' system
Historical
Projected
TJ
300
250
200
150
100
50
0
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
Assumptions:
RCI Energy: Pop'n=Mid, GDP=Mid, Gas share=Mid, Efficiency = Mid
PowerGen: Central
OtherInd
Generation
Steel
Refining
Meat
Paper
Dairy
MM
ToU
Non
Gas_SnD_v06.xlsm



Peak Week demand for All Vector & Maui Tx North of Mokau
Historical
Projected
TJ
2,000
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
Assumptions:
RCI Energy: Pop'n=Mid, GDP=Mid, Gas share=Mid, Efficiency = Mid
PowerGen: Central
OtherInd
Generation
Steel
Refining
Meat
Paper
Dairy
MM
ToU
Non
Gas_SnD_v06.xlsm

7 Summary projections of demand

7.1 Purpose

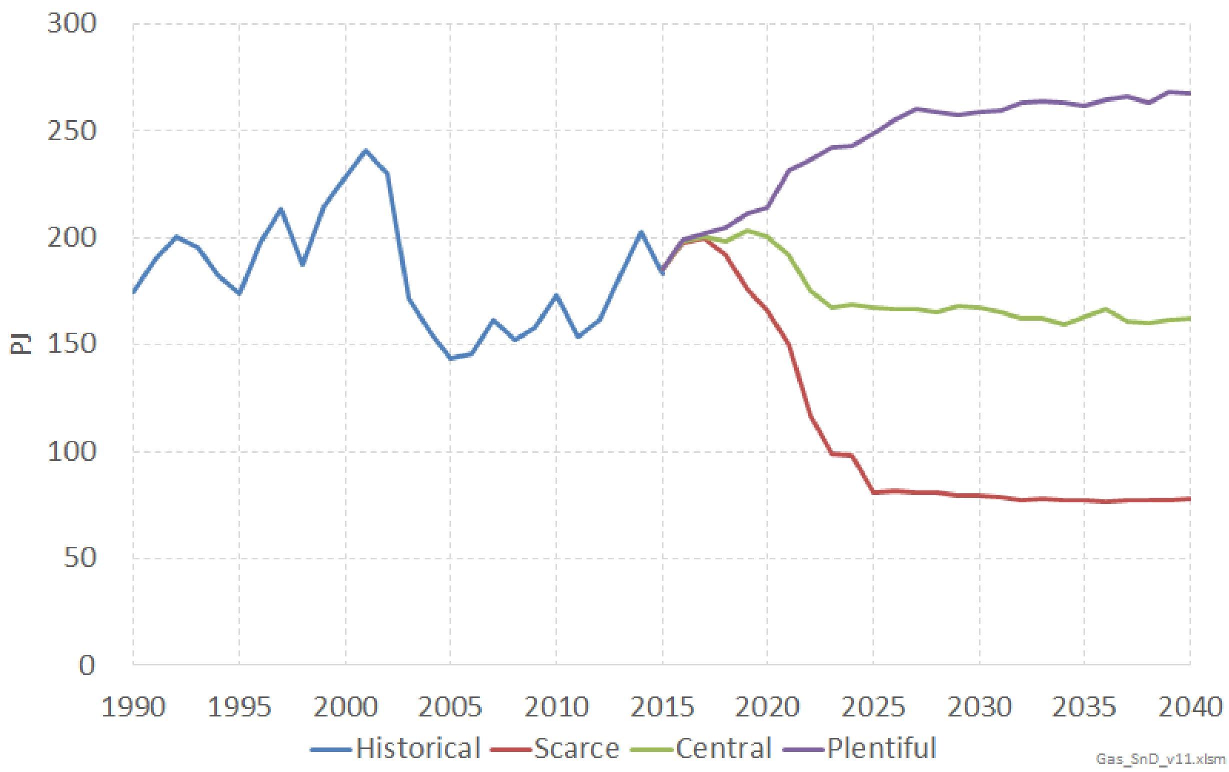
This section describes the overall gas demand projections, based on the sectoral projections discussed in the previous three chapters.

7.2 National gas demand projections

Figure 73 shows the demand projections for 2016-2040 at the aggregate level. Figure 74 shows the same information, but on a 'zoomed in' basis for the next ten years. Key observations are:

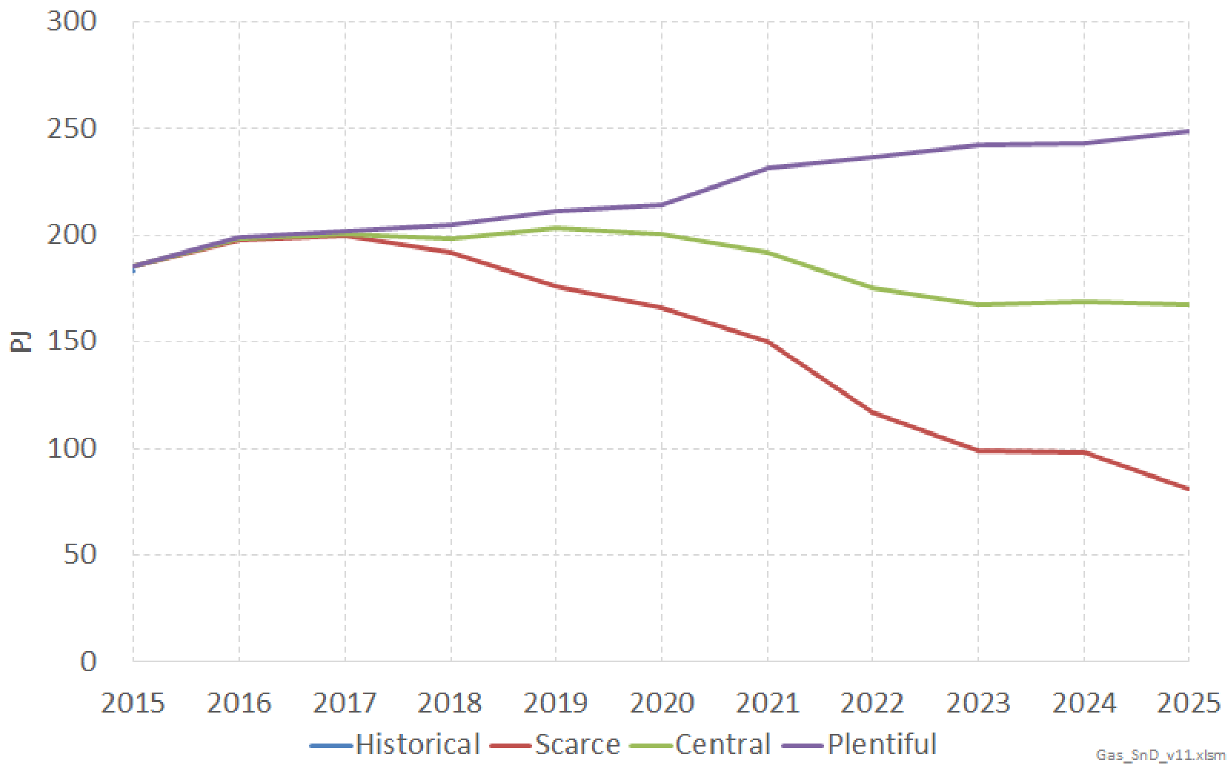
- The projections show a wide range of possible demand levels in future years
- The High, Central and Low scenarios should not be interpreted as equally 'likely' – rather the High and Low cases present possible (but unlikely) 'bookends' for demand – actual outcomes are more likely to be around the Central scenario case – at least for the next few years
- The differences between the scenarios are mainly driven by variations in the 'discretionary' gas users in the petrochemical and power generation sectors – direct use of gas is relatively stable in all scenarios
- Further, it should be noted that the power generation projection in the 'Plentiful' scenario in particular is inconsistent with the governments stated target of achieving 90% of generation from renewables by 2025.
- For the next five years, gas demand is projected to remain around current levels. Further information on drivers may crystallise in the next 12 months – particularly in relation to methanol production plans for plants with scheduled turnarounds in ~2018.

Figure 73: Aggregate gas demand – scenario projections to 2040



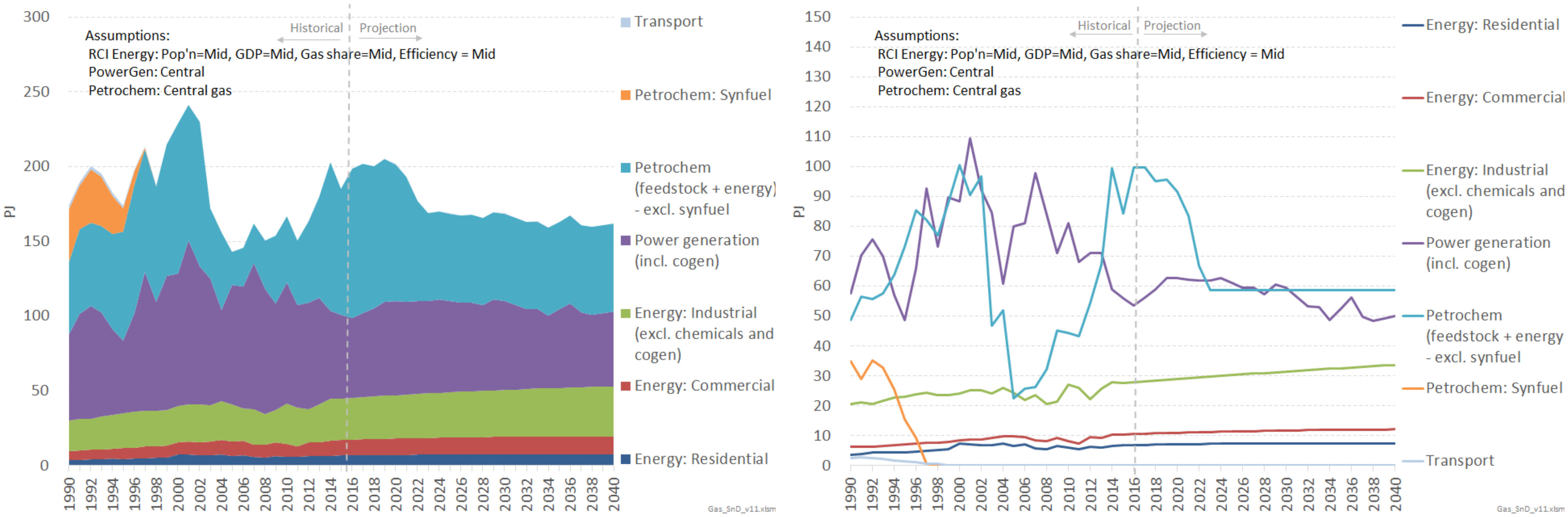
Source: Concept analysis

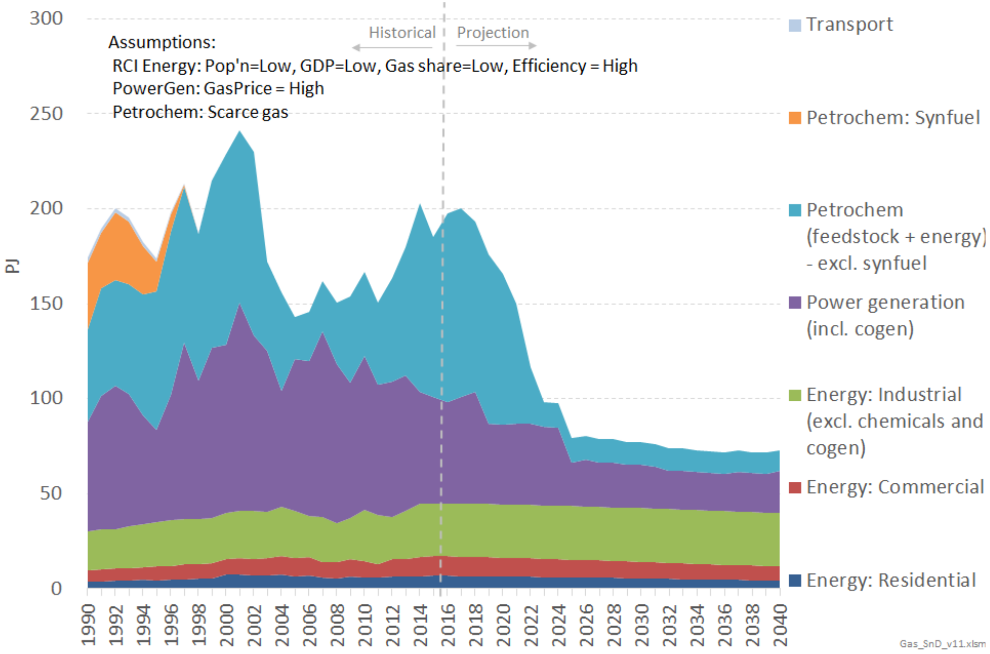
Figure 74: Aggregate gas demand – scenario projections to 2025



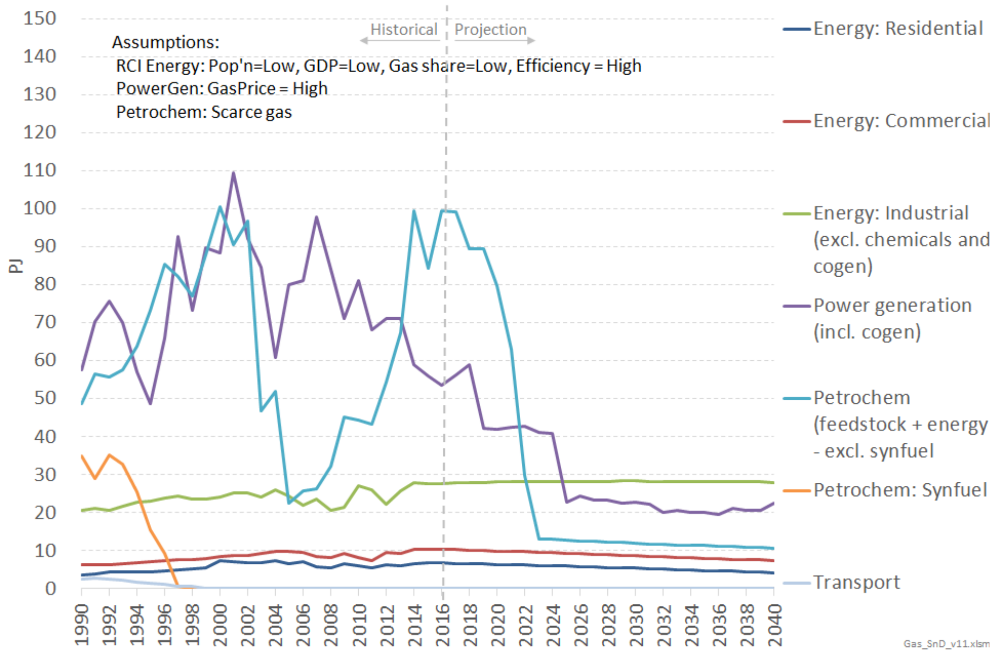
The following graphs show the national projections for the central-case scenario for all the above uses, then the combination of all the low-demand scenarios for each use, followed by the combination of all the high-demand scenarios for each use.

Figure 75: Summary Central, Scarce (absolute Low), and Plentiful (absolute High) national gas demand projections

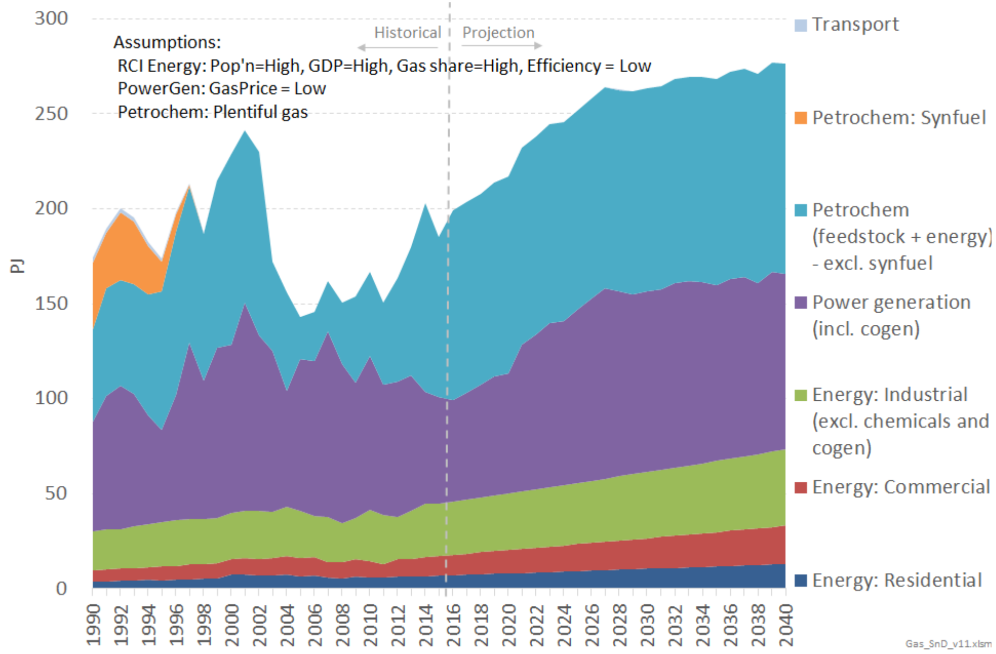




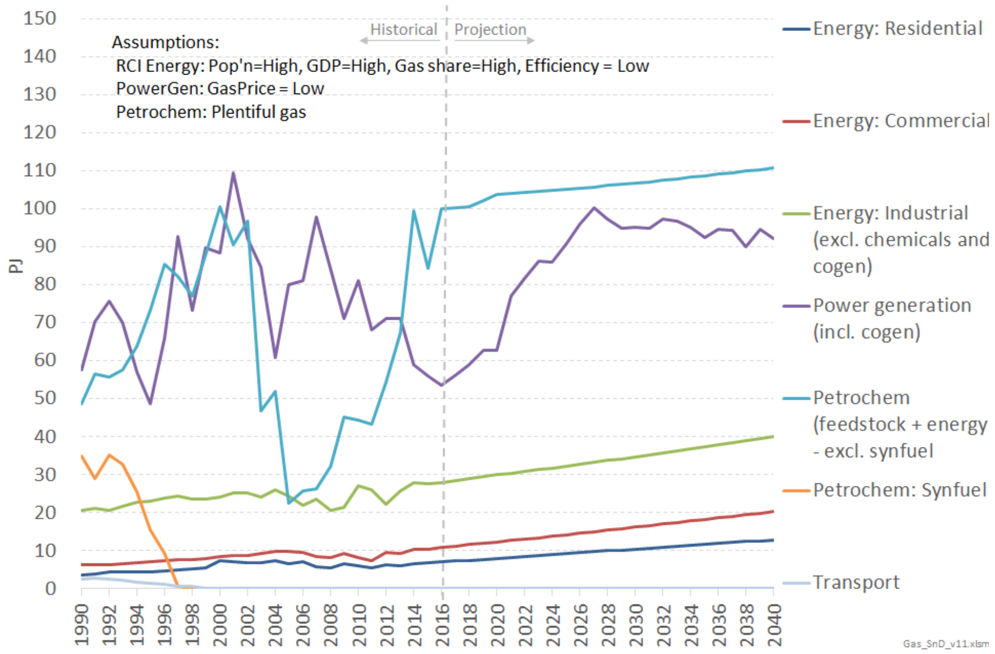
Assumptions:
RCI Energy: Pop'n=Low, GDP=Low, Gas share=Low, Efficiency = High
PowerGen: GasPrice = High
Petrochem: Scarce gas
Historical
Projection
PJ
Transport
Petrochem: Synfuel
Petrochem (feedstock + energy) - excl. synfuel
Power generation (incl. cogen)
Energy: Industrial (excl. chemicals and cogen)
Energy: Commercial
Energy: Residential
Gas_SnD_v11.xlsm



Assumptions:
RCI Energy: Pop'n=Low, GDP=Low, Gas share=Low, Efficiency = High
PowerGen: GasPrice = High
Petrochem: Scarce gas
Historical
Projection
PJ
Energy: Residential
Energy: Commercial
Energy: Industrial (excl. chemicals and cogen)
Power generation (incl. cogen)
Petrochem (feedstock + energy - excl. synfuel
Petrochem: Synfuel
Transport
Gas_SnD_v11.xlsm



Assumptions:
RCI Energy: Pop'n=High, GDP=High, Gas share=High, Efficiency = Low
PowerGen: GasPrice = Low
Petrochem: Plentiful gas
Historical
Projection
PJ
Transport
Petrochem: Synfuel
Petrochem (feedstock + energy) - excl. synfuel
Power generation (incl. cogen)
Energy: Industrial (excl. chemicals and cogen)
Energy: Commercial
Energy: Residential
Gas_SnD_v11.xlsm



Assumptions:
RCI Energy: Pop'n=High, GDP=High, Gas share=High, Efficiency = Low
PowerGen: GasPrice = Low
Petrochem: Plentiful gas
Historical
Projection
PJ
Energy: Residential
Energy: Commercial
Energy: Industrial (excl. chemicals and cogen)
Power generation (incl. cogen)
Petrochem (feedstock + energy - excl. synfuel
Petrochem: Synfuel
Transport
Gas_SnD_v11.xlsm

Appendix A. Future gas supply options

This appendix outlines a range of possible supply options to meet future demand for gas.

Conventional gas - Taranaki basin

All of New Zealand's existing gas production is from onshore and offshore fields in the Taranaki basin. It has also attracted the lion's share of exploration effort over time in New Zealand. Nonetheless, compared with other petroleum basins around the world with a 40+ year production history, the Taranaki basin remains lightly explored.

Taranaki is the most likely source for new gas supply in New Zealand, at least for sources of gas demand connected to the existing North Island transmission system.

New supply from Taranaki is likely to comprise a mix of:

- Development of additional gas sources from within existing producing fields.
- Discovery and development of new gas sources close to existing production facilities (especially important for offshore production).
- Discovery and development from new sources.

Conventional gas - ex-Taranaki basin

In addition to the Taranaki basin, there are 17 other identified basins within the country's territorial jurisdiction as shown in Figure 76.

New Zealand has sovereign rights to over 5.7 million square kilometres of land and seabed.[78] A large proportion of this territory has not been explored other than by reconnaissance survey. However, the available data suggest that basins which may host oil and gas cover about 20% of New Zealand's territory. Where limited exploration has occurred, it has confirmed the presence of hydrocarbons in a number of cases (albeit at levels judged uneconomic to develop).

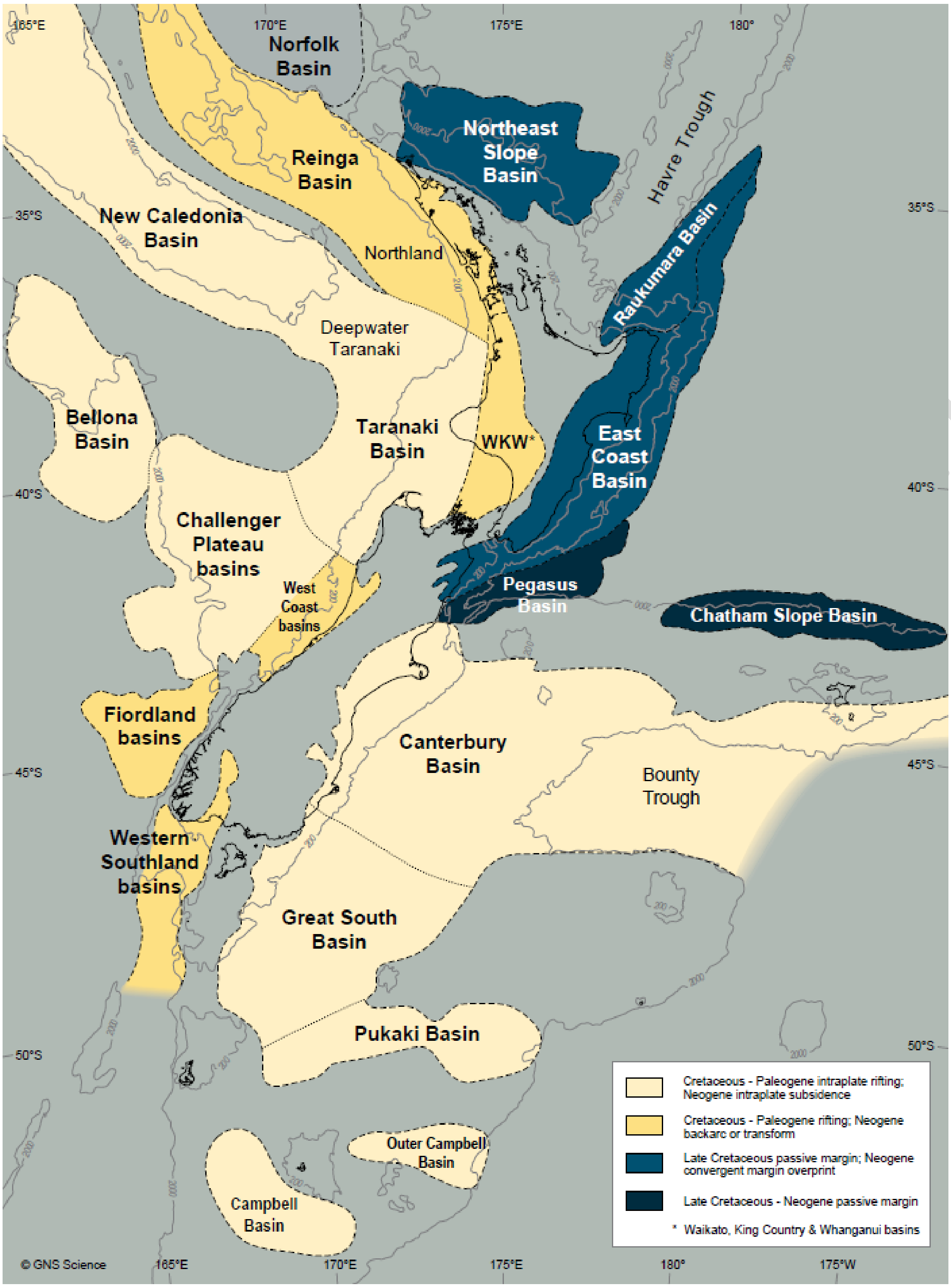
Since the mid-2000s the government has stepped up efforts to encourage exploration in areas outside Taranaki (as well as Taranaki). For example, it has funded seismic acquisition programmes over almost 6,000 km^2 of seabed in the Reinga and Pegasus basins, and the Bounty trough. The industry responded with increased exploration effort, from both existing and new players. While additional hydrocarbon deposits have been identified, none have proven to be commercial to date. More recently, participants have relinquished permits or sought to defer work programme commitments, in response to lower oil prices. Nonetheless, there has been continuing interest in basins outside Taranaki.

While there have been no commercial finds identified to date, there have been encouraging indications in the Canterbury basin. If this discovery is developed, a probable scenario would be for sale to new gas customers in the South Island, especially industrial and commercial users who currently rely on coal. This would be especially attractive given the expectation of rising carbon costs.

More generally, this example raises the issue of how any major find would affect the existing gas market in New Zealand. Most basins are remote from demand centres and existing pipeline infrastructure. Even the closer basins (East Coast, Raukumara) are on the periphery of the existing gas transmission system. In these areas the gas pipeline network has much lower transmission capacity than the main Taranaki – Auckland corridor.

[78] NZ Petroleum and Minerals

Figure 76: Petroleum basins in New Zealand



Source: NZ Petroleum and Minerals

Significant investment to extend or upgrade pipeline capacity would probably be required to connect any major new gas find outside the Taranaki basin into the North Island market. These factors are also expected to be relevant to any major find in deepwater Taranaki, although the magnitude of the effect is likely to be smaller because a new field would be closer to existing pipeline infrastructure.

Another factor is the size of the existing domestic gas market, and its ability to absorb a large new source of gas supply. For example, a sizeable gas find (like say Pohokura or larger) might require annual sales of 60-70 PJ/year to justify the necessary investment in gas processing and transmission infrastructure. This would be equivalent to around one third of existing total gas usage. If existing sources (e.g. Taranaki fields) could meet prevailing demand, a new more distant gas source would be reliant on load growth for its sales. It appears unlikely that demand growth of this magnitude would emerge from existing users.

These considerations suggest that any major new gas find outside of Taranaki is more likely to be directed toward export markets or new local markets, unless Taranaki production is unable to satisfy prevailing demand. The export of gas could take the form of LNG, produced on either a floating facility, or brought ashore for processing. Alternatively, gas might be used as a feedstock and exported in the form of petrochemicals (e.g. methanol) from a newly constructed plant. In either case, from a gas producer's perspective, export would remove the dependence on the relatively small scale domestic market and allow gas to be produced on a relatively flat profile, minimising costs and accelerating liquids recovery.

In conclusion, it appears relatively unlikely that any major gas find remote from the existing transmission system would be physically interconnected to the existing North Island gas market unless Taranaki supply is insufficient. Instead, it is more likely that such a find would be directed to export. In that case, a major gas find would be unlikely to have a significant commercial impact on the North Island gas market.

Unconventional gas

New Zealand is known to have unconventional gas sources, and there was an increased level of activity in this segment in the 2010-2014 period, although this has since waned with the recent weakness in oil prices.

Shale resources

Over 50 wells have been drilled in the East Coast Basin since the 1970s focussing on conventional oil prospects. A number encountered oil or gas, but none yielded a commercial discovery. More recent exploration targeted a mix of conventional reservoir targets, and unconventional opportunities in shale formations that are believed to be the source rocks for the basin's entire hydrocarbon system.

The East Coast shale formations were not targeted in previous oil and natural gas drilling because they were regarded as being too impermeable. The recent improvements in unconventional oil and gas technology stimulated stronger interest in the resource by some parties. On the other hand, some industry observers remain sceptical about the potential for commercialisation of East Coast shale resources, citing the extensive faults in the underlying structures, difficult terrain and relative distance to infrastructure.

One of the parties which had shown strong interest in the region is TAG Oil (TAG), which secured exploration permits over 7,000 square kilometres of onshore land in the East Coast basin and undertook some drilling. TAG has subsequently abandoned and plugged these wells, noting that it had encountered extremely difficult drilling conditions. TAG has since refocused its exploration and development efforts in Taranaki.[79]

Coal seam gas

CSG wells have been drilled in the Taranaki, Waikato, Whanganui, West Coast and Southland basins. Although a number of CSG have been identified through this process, none have been brought into commercial production. We expect that monetising the resources would be challenging due to a lack of infrastructure to convey gas to market in most cases.

[79] See www.tagoil.com/news/tag-oil-announces-abandonment-plans-at-waitangi-valley-1-and-return-to-drilling-of-core-production-assets-in-taranaki/

Underground coal gasification

In 2012, Solid Energy trialled underground coal gasification (UCG) in the Waikato area. Solid Energy stated that it had access to around 2 billion tonnes of coal resource in the Huntly area, much of which was too deep to mine using conventional techniques. Solid Energy considered that UCG may be a viable way to access the resource, which it assesses as having a large energy potential (>1,000 PJ)[80]. This project was subsequently shelved when Solid Energy experienced financial difficulties due to falling coal prices. Commercialisation would also be complicated by the fact that the produced gas would not meet national pipeline specification, and therefore require dedicated infrastructure.

Potential for gas importation

Gas importation has been considered in the past for New Zealand. In the mid-2000s, Contact Energy and Genesis Energy assessed the viability of LNG importation as a backstop option, in the event that local production was insufficient to meet demand. The project progressed to a point of identifying a preferred terminal site (Port Taranaki) and preliminary design.

A key risk for the project was potential stranding of onshore tankage required to receive LNG shipments. The project partners indicated that the minimum scale for viability was likely to be around 60PJ per annum. Work on the concept was later shelved by the parties with the improving outlook for domestic gas supplies.

Since that study was completed, there has been further technological development within the LNG sector. One option is a floating buoy connected to the onshore gas pipeline system, which avoids the need for dedicated port infrastructure. These require onshore storage to receive and store gas. Another option is a dockside LNG vaporization and natural gas receiving facility.

These types of facility could lower the in-country investment requirement, reducing stranding risk and development time. However, LNG is still expected to be a relatively expensive option because of the costs of liquefaction and shipping (in addition to underlying commodity cost) and involve a multi-year lead-time.

Further, as detailed in section 5, changes in the relative economics of renewable versus thermal generation means that there is likely to be significantly reduced demand for gas for power generation than when LNG importation was considered in the mid-2000s.

Based on current information, gas importation appears unlikely and would probably only be seriously re-evaluated if there was a sharp and sustained reduction in reserves cover.

---

80 See www.coalnz.com/index.cfm/1,477,0,0/Solid-Energy-begins-Underground-Coal-Gasification-successfully.html

Appendix B. Information on wholesale gas prices

This section provides an overview of recent trends in gas prices based on public information sources. Because almost all wholesale gas trading in New Zealand is conducted via bilaterally negotiated agreements on confidential terms, there is limited information in the public domain. This means that the price information should be treated as broad guide.

Data from MBIE disclosures

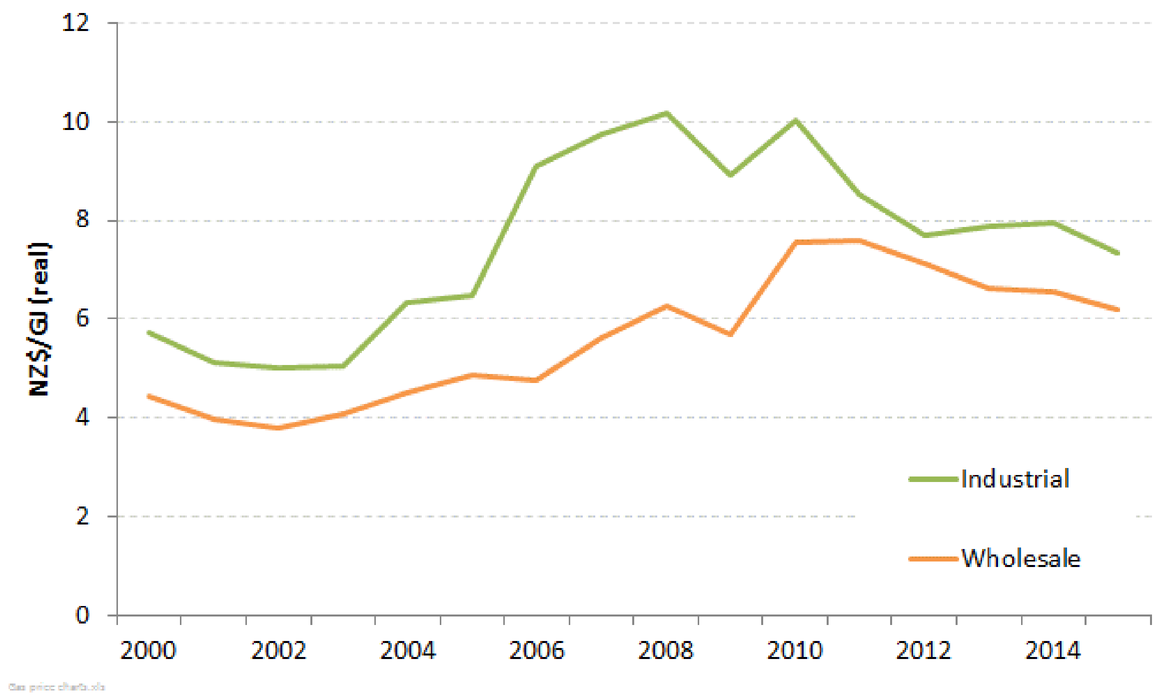
The Ministry for Business, Innovation and Employment (MBIE) publishes data on gas prices over time. This data is based on *prevailing* contracts. It therefore reflects market conditions at the time the relevant contracts were struck, rather than conditions at the time the data is reported. The timing difference can be significant, as contracts are typically for a minimum duration of 2-3 years, and some gas contracts are for considerably longer (e.g. 5-10 years or more).

Furthermore, the data is typically reported in a raw form, with little or no adjustment to account for differences in contract terms. For example, some gas contracts are quoted for delivery at the customer premises and therefore include pipeline transport costs. Gas contracts also vary in the degree of swing provided to buyer/seller. These factors need to be borne in mind when making price comparisons across customer types, contracts and time periods.

Figure 77 shows reported average gas prices paid for reticulated industrial users based on government data.[81] These prices include pipeline transportation costs. As a broad guide, pipeline costs are around \$0.6 - \$1.5/GJ (varying for each user) and these need to be deducted from reported figures to derive the gas price received by the seller.

The chart also shows a "wholesale" category reported in the official statistics. The definition of this category is not entirely clear, but we understand that gas for power generation (including cogeneration) accounts for most of this usage in this group.

Figure 77: Delivered gas prices (real, Sept 2015 \$)



Source: Concept analysis of MBIE data

[81] Prices for commercial and residential users are much higher, mainly because of the greater proportion of pipeline costs, and the premium for swing (noting these users typically have a lower load factor).

Key observations are:

- Prices paid by industrial and wholesale users moved up in the period 2003 to 2010 – largely due to the tighter supply/demand position following the Maui redetermination in 2003. Since 2010 real gas prices have eased somewhat, reflecting the increased reserves to production cover.
- Prices paid by wholesale users and industrial customers followed a similar track – with the former being lower than the latter. This is likely to reflect the influence of greater transport costs for industrial users on average.

Looking at trends over time, the difference between prices paid by industrial and wholesale users has changed quite significantly. It was around $1.5/GJ in the early 2000's and rose to around $4/GJ in 2008. This is probably due in part to different segments contracting on varying durations. However, it probably also reflects differing levels of competition across market segments.

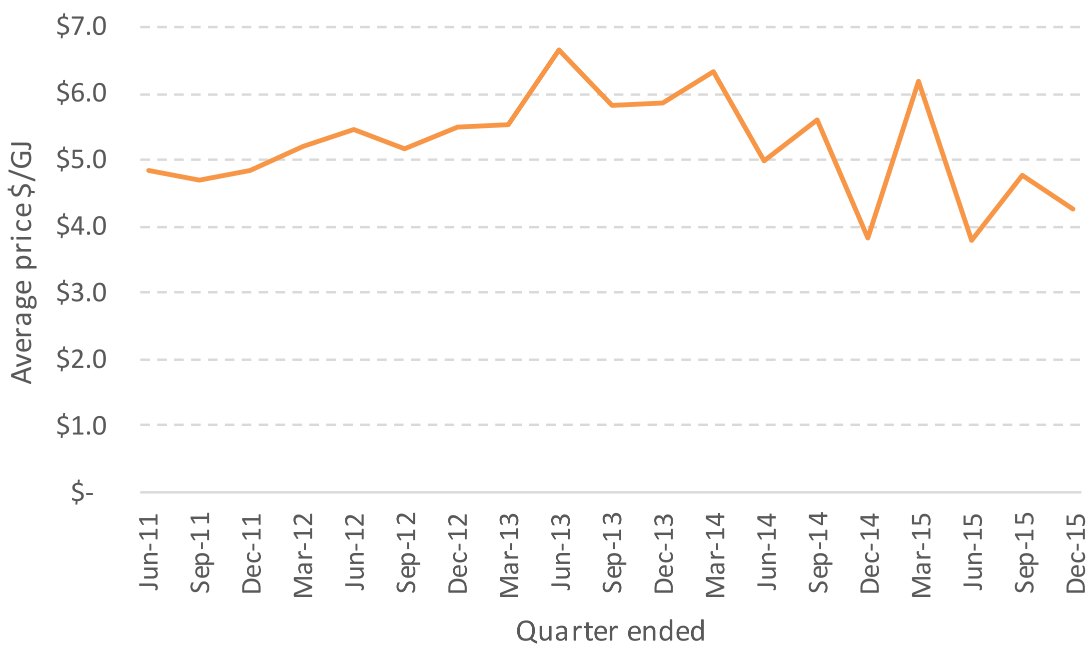
Contract prices

As noted earlier there is very limited public data on gas prices at the individual buyer or producer level. One exception is TAG Oil, which discloses quarterly gas revenues and volumes.

TAG Oil's operates the Sidewinder and Cheal gas-condensate fields. The daily gas production profile from these fields suggests that oil production has been the priority – for example there is no clear seasonal or business day/non-business day modulation. For this reason, the average gas price for this profile is likely to be at a discount to a gas contract with a flat profile or which provides the customer with discretionary swing.

Figure 78 shows the average price reported by TAG Oil for gas sales each quarter.

Figure 78: TAG Oil – average price for gas sales



Source: Concept analysis of TAG Oil disclosures

The average gas price received by TAG Oil has varied between approximately $4/GJ and $6.5/GJ, with some softening apparent over the 2014-2015 period, to around $4.5/GJ. In mid-April 2016 TAG Oil issued guidance for FY2017 indicating an expected gas price of NZ$4.75/ GJ with a scheduled increase to NZ$5.10/ GJ in January 2017.[82] This may indicate an expectation of some firming in prices going forward.

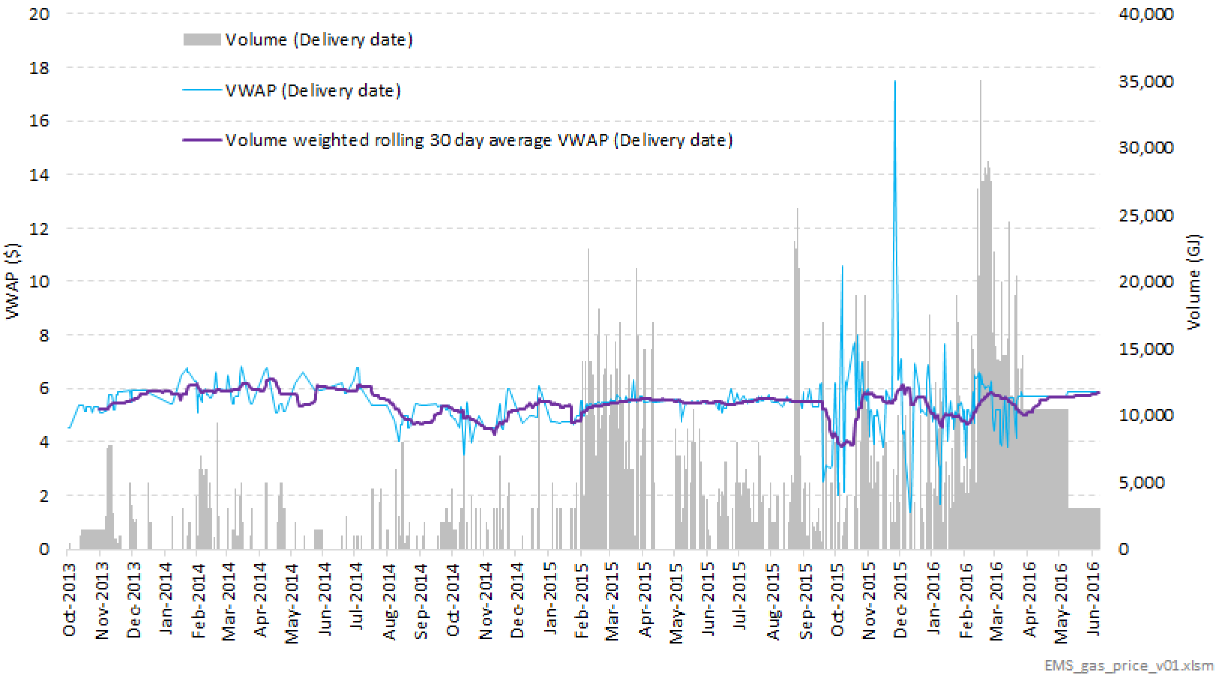
[82] See http://www.tagoil.com/news/tag-oil-announces-fy2017-capital-budget-and-guidance/

Spot gas prices

While the bulk of gas trading occurs on bilateral contracts, a small but growing proportion of sales are occurring on the platform operated by emsTradepoint. This offers day-ahead and on-the-day markets. It allows parties to trade on an anonymous basis, and the market publishes prices and volumes for all trades. Since October 2015, this market has been used as the main source of gas for residual balancing actions on the main transmission system.

Figure 79 shows the prices, rolling 30 day volume weighted average prices, and daily volumes since the market commenced.[83]

Figure 79: Volume weighted average price and trade volumes



Source: Concept analysis of emsTradepoint data

Key observations are:

- Spot prices were in a relatively tight band of $5-$7/GJ for most of the period to October 2015. Since then, there has been much greater volatility, coinciding with the use of this market for pipeline balancing purposes.
- The rolling 30 day volume weighted average price (VWAP) has generally been around $6/GJ, although it has deviated significantly from these levels at times.
- Volumes being traded have increased over time, especially from October 2015 when the platform has been used for balancing gas transactions on the Maui pipeline.

83 Data are shown based on value date for each transaction, noting that the trade dates may differ. However, most trades have been for gas on the day or a few days ahead so the series is a broad indication of 'spot' prices.

Appendix C. Approach to developing distribution network demand projections

Our previous Gas Supply / Demand studies[84] adopted a relatively high-level approach to develop gas demand projections, focusing on the major demand drivers.

However, for this current Supply / Demand study, the Commerce Commission has liaised with Gas Industry Company to determine whether the projections could be developed in a more detailed form. This would facilitate their use as inputs in the Commission's forthcoming price-quality determinations for regulated gas pipeline businesses.

Accordingly, for this 2016 study, the projections have explored in greater depth:

- The potential nature and scale of outcomes from the various different drivers on gas demand;
- The extent to which different drivers may vary on a regional basis – particularly for the different distribution networks;
- The range of uncertainty on future gas demand due to:
  - Inherent uncertainty over future drivers of demand;
  - Lack of historical data on which to base future projections; and
  - Modelling error.

While the 2016 projections have explored these issues in greater depth, we note that the modelling approach is still relatively high-level, reflecting both the scope of the exercise, and the inherent uncertainties for a task of this nature.

This Appendix describes the approach taken for developing these demand projections. It first reports on observed changes in network demand over the past four years, before describing how the projections of future demand were developed, and then presenting the results.

Historical movement in gas distribution demand

We have analysed the reported levels of distribution network demand over the four financial years to 2015, as disclosed to the Commerce Commission. These disclosures were analysed for the main reported distribution networks: Vector Auckland, Vector Non-Auckland (now First Gas), Powerco Central, Powerco Lower, and GasNet. For the purposes of the charts shown in this analysis, these networks are referred to as: Vec Auck, 1Gas NonAuck, PCo Central, PCo Lower, and GsN GasNet.

The network companies submitted their disclosures on the basis of load groups. We have assigned these group to three main customer segments: Residential, Commercial and Industrial ('Res', 'Com', and 'Ind'). The assignment of a load group into segments was largely based on the network companies' own classifications.

The results of the comparisons are shown in Figure 80 to Figure 85, looking variously at changes at a total network level, as well as on an individual customer segment basis.

The graphs are generally presented in absolute terms (i.e. annual quantities) followed by a presentation on an index basis which show the relative change from the first year of the data series. For these index representations, the first year value is set to 100, with subsequent years representing the percentage difference relative to this first-year value.

[84] See http://www.gasindustry.co.nz/work-programmes/gas-transmission-investment-programme/supply-and-demand/#long-term-gas-supply-and-demand-scenarios

The key observations from the analysis are:

- There have been material changes in demand over this four-year period – at both the network and customer segment level in some cases
- Where changes have occurred, there is not necessarily any consistent trend over time
- There appears to have been some re-classification of load groups between FY13 and FY14 in the two Vector-owned networks (noting that 1Gas NonAuck was owned by Vector until recently), as shown in Figure 82
- The apparent re-classification has affected customers in the “Com” and “Ind” customer segments.

Figure 80: Reported total annual quantity delivered across different networks and for different customer segments

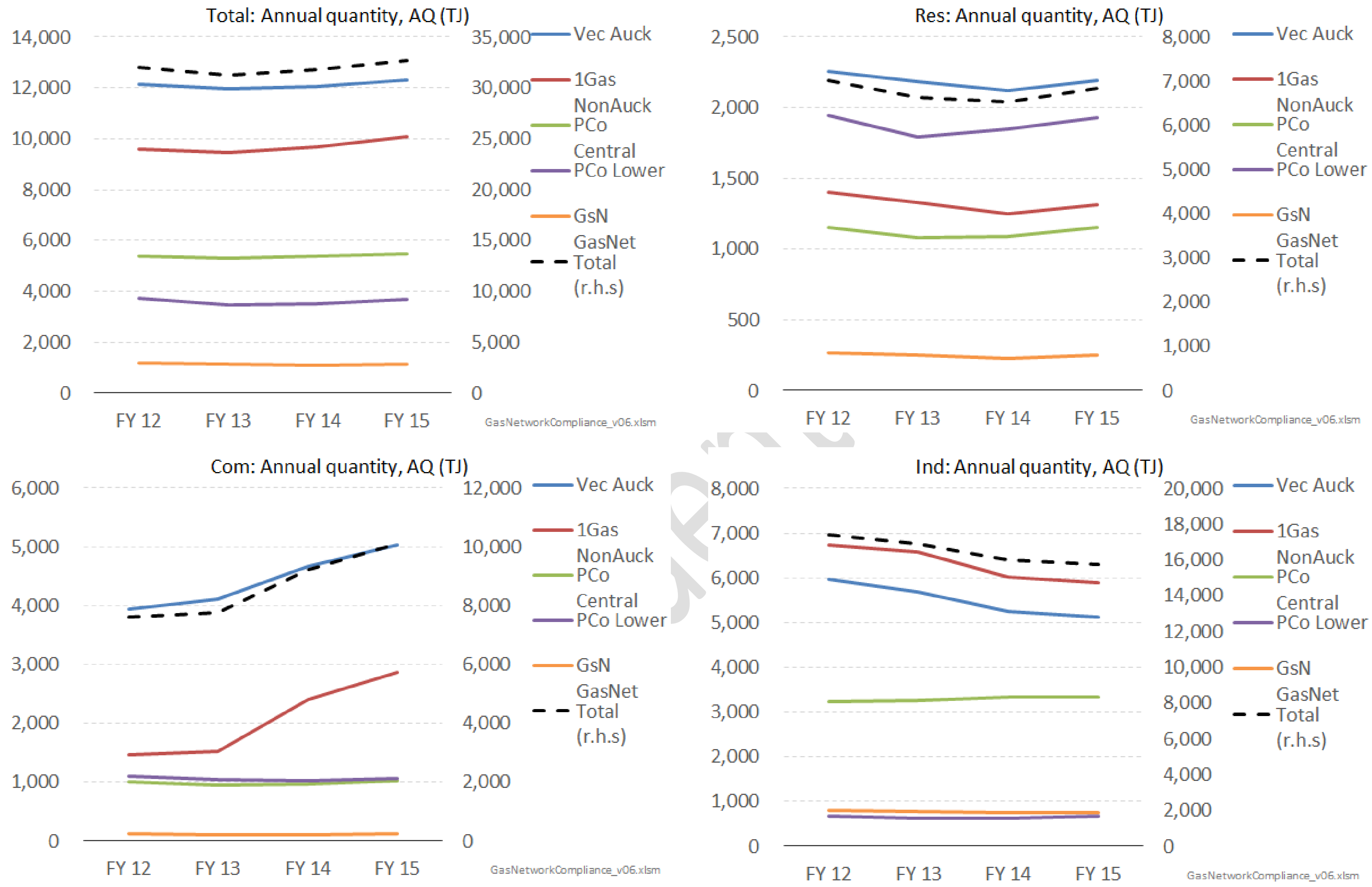


Figure 81: Reported relative change in total annual quantity delivered across different networks and for different customer segments

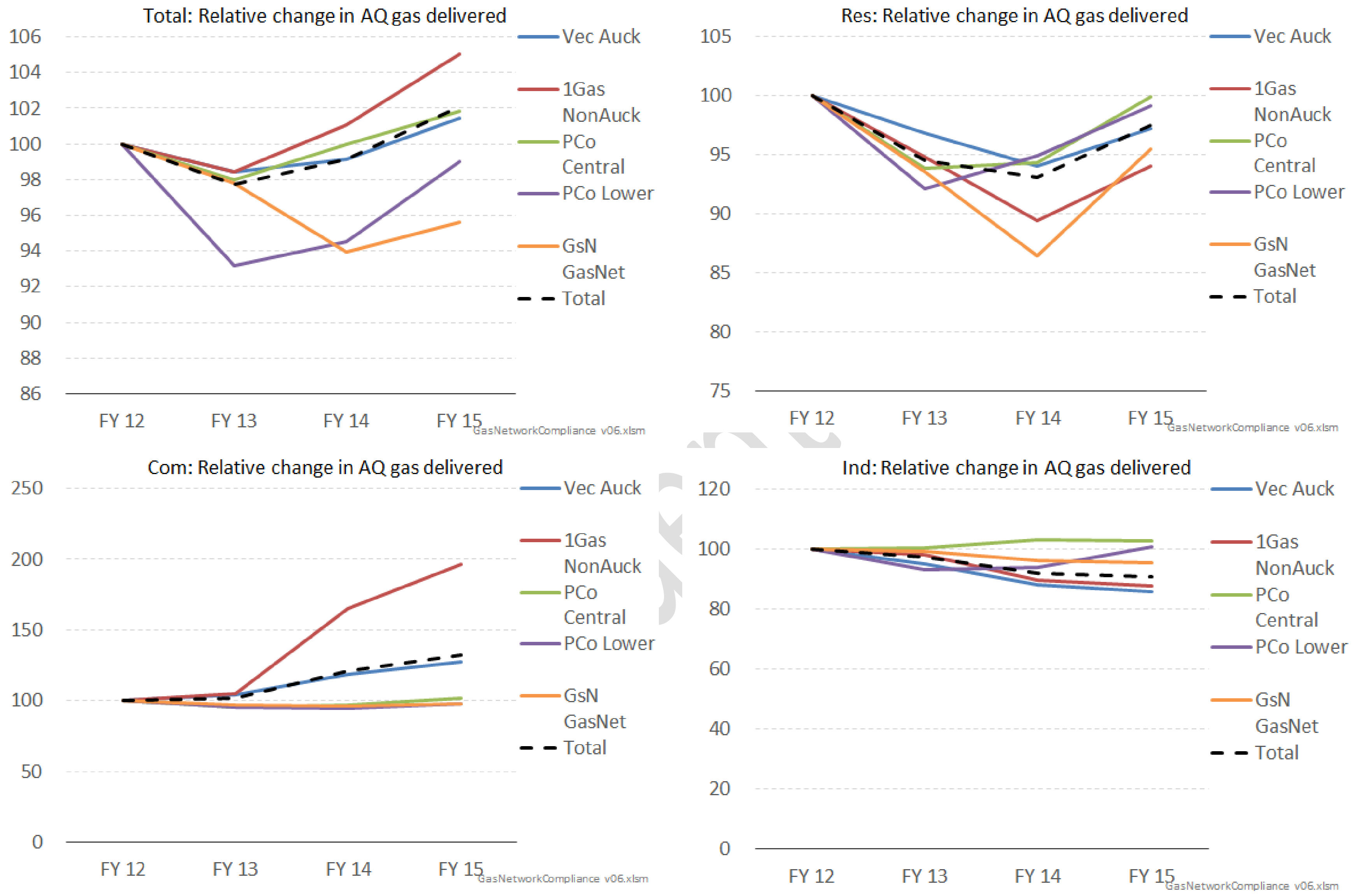
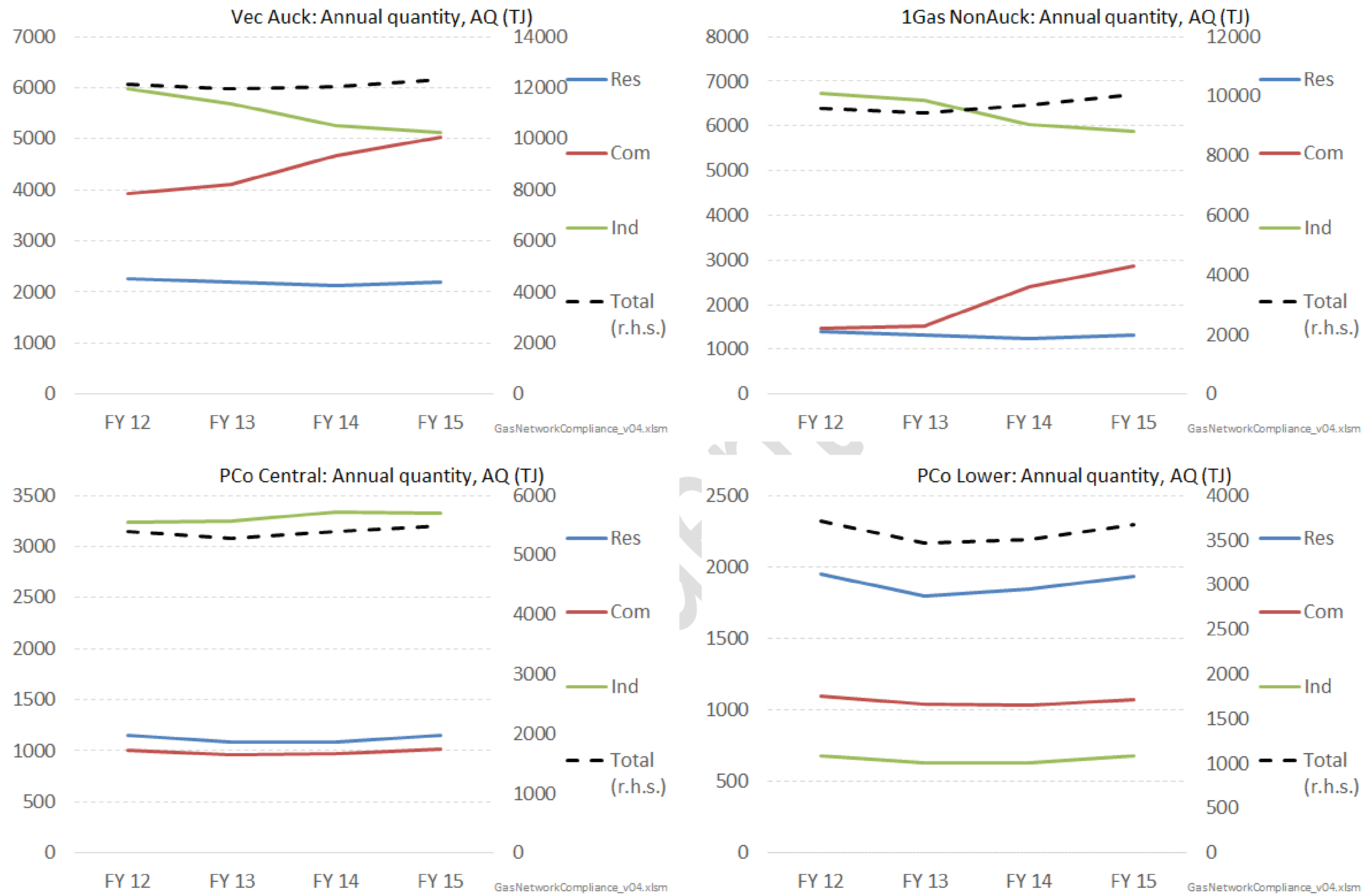


Figure 82:Reported total annual quantity delivered across different customer categories for each network



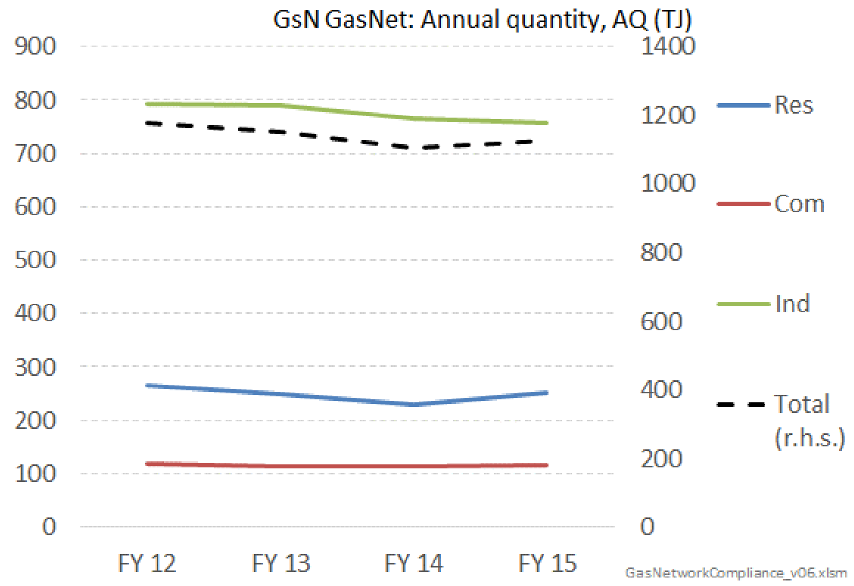
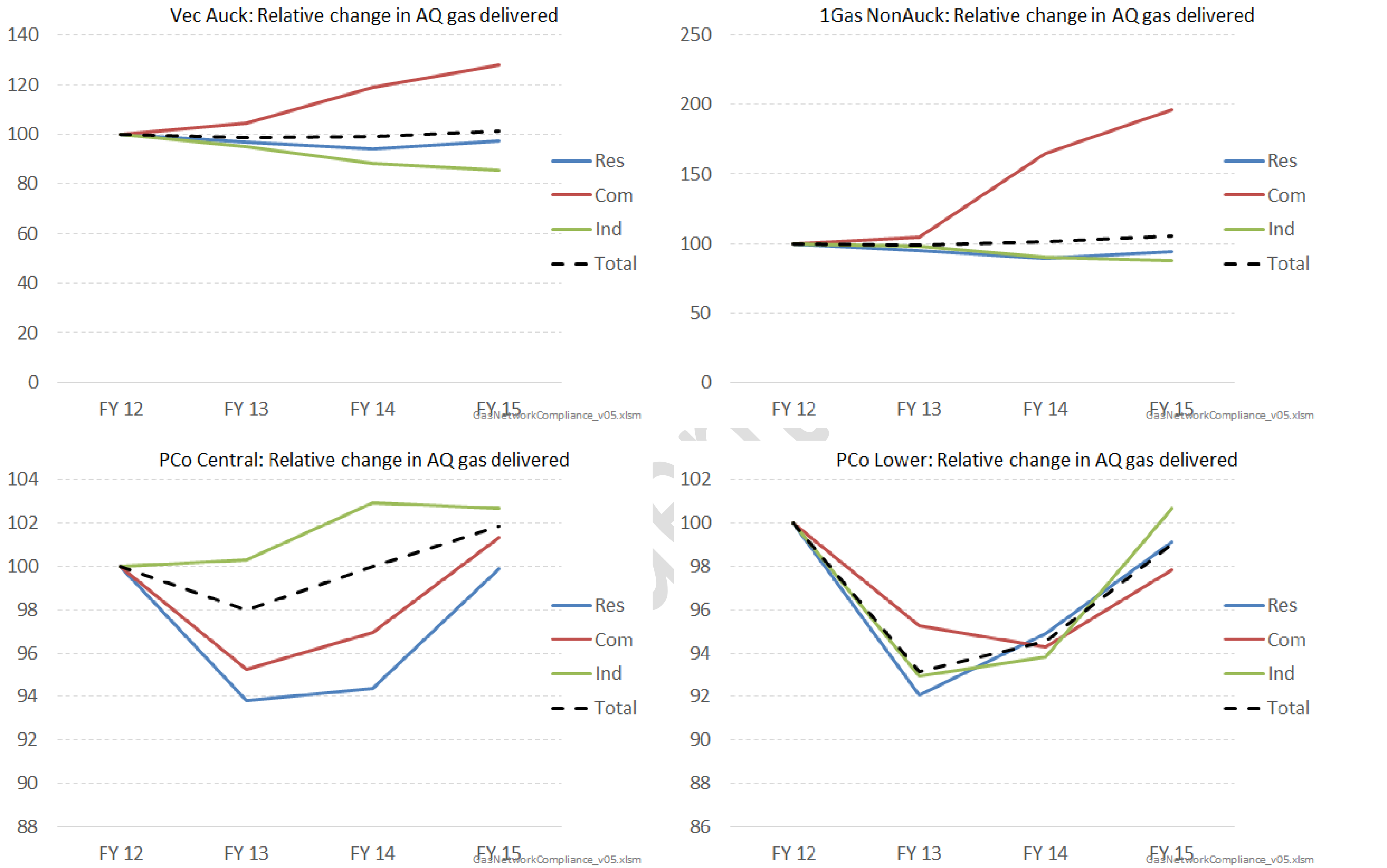

GsN GasNet: Annual quantity, AQ (TJ)
900
800
700
600
500
400
300
200
100
0
1400
1200
1000
800
600
400
200
0
FY 12
FY 13
FY 14
FY 15
Res
Com
Ind
Total (r.h.s.)
GasNetworkCompliance_v06.xlsm

Figure 83: Reported relative change in total annual quantity delivered across different customer categories for each network



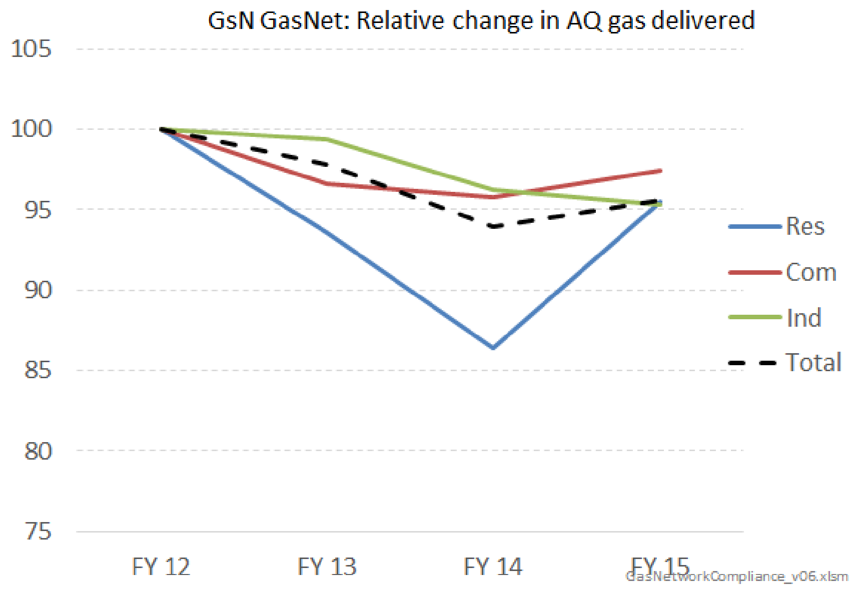

GsN GasNet: Relative change in AQ gas delivered
105
100
95
90
85
80
75
FY 12
FY 13
FY 14
FY 15
Res
Com
Ind
Total
GasNetworkCompliance_v06.xlsm

Figure 84: Reported relative change in number of residential ICPs and average demand per residential ICP across different networks

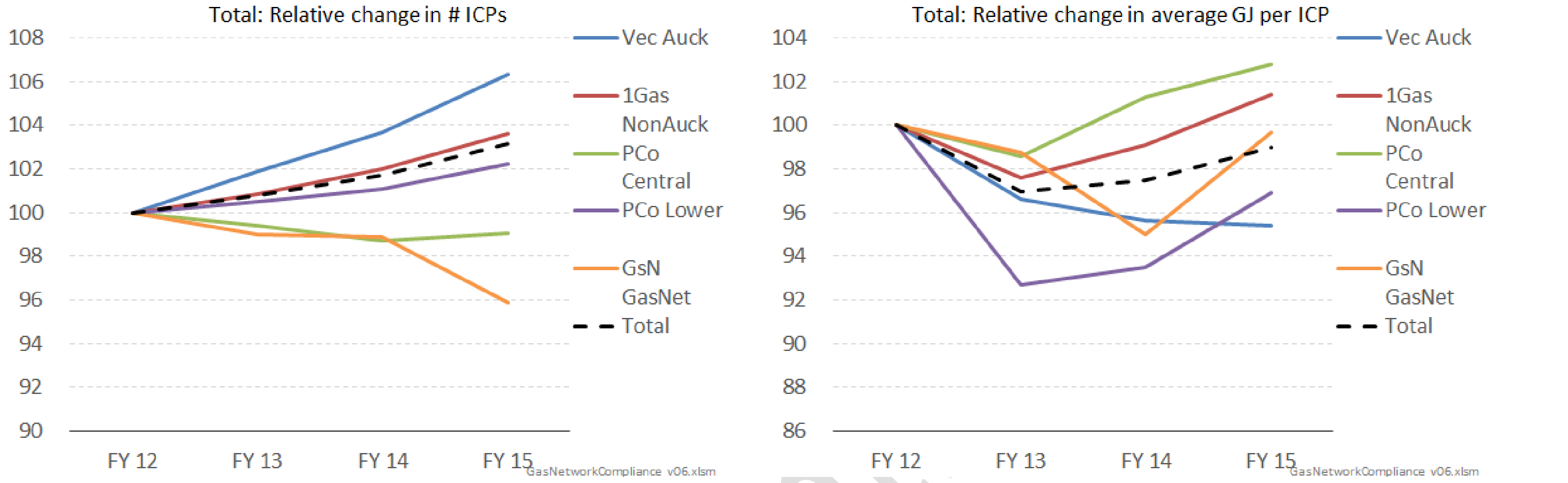
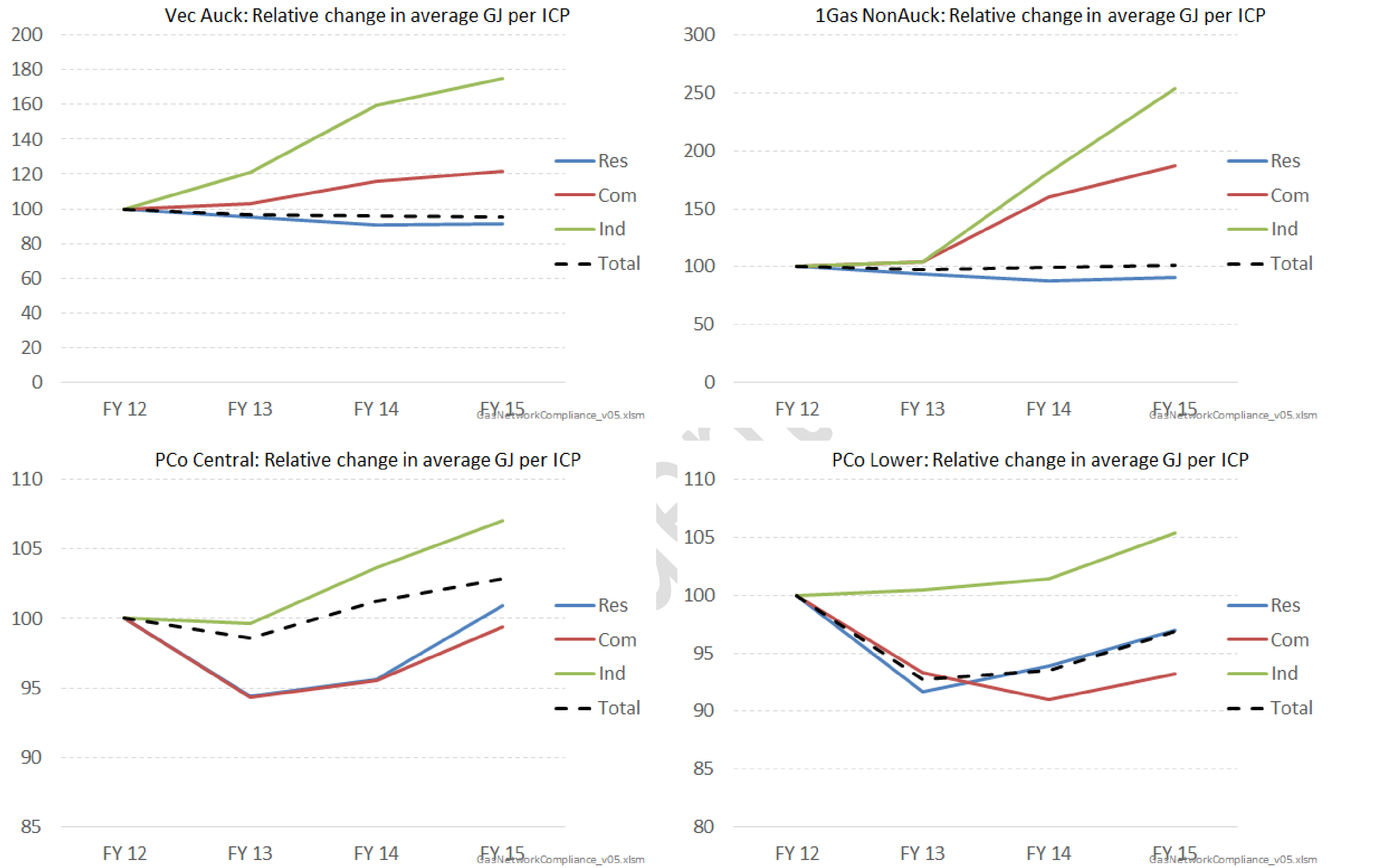
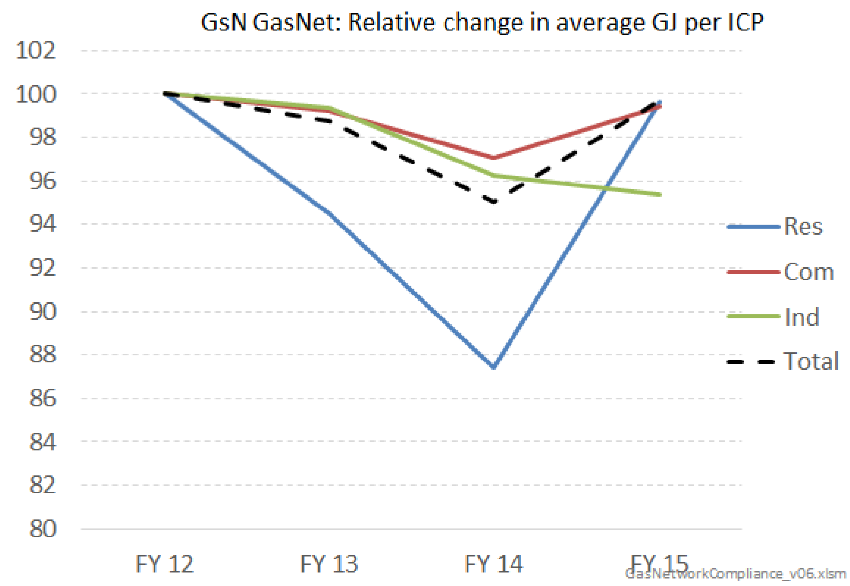


Figure 85: Reported relative change in average demand per ICP for different customer segments for each network




GsN GasNet: Relative change in average GJ per ICP
102
100
98
96
94
92
90
88
86
84
82
80
FY 12
FY 13
FY 14
FY 15
Res
Com
Ind
Total
GasNetworkCompliance_v06.xlsm

Conceptual approach for considering future gas demand

One possible approach to developing projections of gas demand would be to

1. Source historical data series of gas demand and various other possibly-causal variables (e.g. population, ICP numbers, GDP, weather/climate, gas prices, etc.)
2. Perform a multi-factor regression analysis to identify the inter-relationships between these possibly-causal 'predictor' variables and develop a model which could predict, for a given combination of values for these predictor variables, the likely level of gas demand.
3. Source reliable forecasts of the identified predictor variables which could be used in the regression model to develop demand forecasts.

For the 2012 study, analysis was undertaken to see if such predictive relationships could be identified. However, it concluded it was not feasible to develop a regression approach that could be used as a reasonable predictor of future gas demand. The key constraints that were identified were:

- ***Lack of data***. This was on a number of dimensions:
  - *Limited historical time-series*. To develop relationships with statistical significance, it is necessary to have a reasonable number of data points. For this current exercise looking at distribution network gas demand, there are only four data points, representing the gas demand disclosed by the network companies to the Commerce Commission for the financial years 2012 to 2015. This is too small to draw statistically robust inferences.
  - *Limited visibility of likely predictor variables*. It is not sufficient to consider the drivers of the demand for *energy* (as distinct to gas alone) – e.g. population, economic growth, etc. –because gas is a discretionary fuel that can be substituted by/for other fuels. Thus, a key driver of gas demand is its relative competitiveness against these other fuels. To address this requires data that can be used to assess this competitiveness dynamic. This is not simply a case of looking at gas and electricity prices (and LPG and wood prices in many cases). Such analysis also requires assessment of:
    - the structure of those prices (i.e. balance between fixed and variable)
    - appliance costs, efficiencies, and useful lifetimes, for the different uses of gas (e.g. space heating, water heating, cooking, process heat)
    - analysis on the levels of demand for these different end-uses of gas
      - Aggregate demand for both gas and for these alternative fuels for the end-use.
      - The 'size' distribution of demand for consumers – i.e. the range of different individual consumer demands (noting that the presence of capital and fixed costs can materially impact on the relative economics of different fuel choices depending on whether consumers consume large or small amounts of energy)
  - *Some predictor variables being a poor proxy for the 'true' underlying driver.* GDP was identified to be a poor proxy for commercial and industrial demand, particularly on an individual business segment basis. This was because
    - GDP is also affected by changes in the quantities and prices of commodities (e.g. milk powder), whereas it is principally the quantity of a commodity produced that is the key driver of energy demand
    - Structural changes in the economy (in particular a progressive move away from primary and manufacturing industries, to service-based businesses) are affecting the relationship between GDP and energy consumption.
- ***The instability of some relationships***. In order for a model to be a useful predictor of future outcomes, relationships identified in the past need to hold stable for the future. This will allow the

impact of a change in a predictor value to be reasonably modelled. However, with regards to technology uptake, changes in prices can result in non-linear outcomes. For example, once the price of a technology passes beyond a threshold, exponential growth can occur before levelling off (e.g. an 'S-curve' type of uptake). This is likely currently being seen with heat pumps, is being witnessed with solar PV overseas, and could potentially occur with other consumer energy technologies that have yet to reach their 'tipping point'. Such phenomena are extremely hard to model. For example, a regression-based demand forecast of Australian grid electricity demand undertaken in 2010 would not have been able to predict the uptake or impact of solar PV, as up to 2009 there had been virtually no uptake of any material scale on which to develop forecast relationships.

In this vein, it may potentially be the case that future CO_2 prices that are much higher than have been experienced in the past result in changes in consumer demand that are very hard to predict.[85]

Similarly, expected future changes to the structure of consumer electricity prices (as indicated by the Electricity Authority in it recent distribution pricing principles consultation) are likely to materially impact on the relative competitiveness of electricity and gas appliances in a way which is inherently hard to predict. Appendix A of the latest Consumer Energy Options report presents some analysis describing the nature and potential scale of such outcomes.[86]

Given that a multi-factor regression approach is not viable, two alternative approaches were considered:

- Simple trend projections
- 'Structural' simulations.

With regards to simple trend projections, the analysis on historical movements in gas demand shown previously on page 117 indicates that there is no clear or consistent trend for gas consumption for the different gas distribution networks – either on a network basis, or on a customer segment basis. Further, as the discussion above highlights, trend projections implicitly assume that historical outcomes are likely to persist to similar degrees into the future – whereas there is a reasonable likelihood that this is unlikely to be the case. Accordingly, this was not considered an appropriate basis on which to develop projections.

Description of structural demand projection model

By a process of elimination, a 'structural' model approach was chosen as the basis on which to develop projections. Such an approach simulates outcomes by developing a model which attempts to capture the expected logical relationships between variables on a deterministic basis.

However, given the inherent uncertainties which frustrated the development of a regression model, it should be appreciated that this approach inevitably has a significant margin of error – something which we seek to address through sensitivity analysis. However, we acknowledge that a structural approach inherently requires significant judgement to be exercised on the part of the forecaster.

A key design choice in developing a structural model is whether to develop the functionality to try and reflect an expected demand driver (e.g. the relationship between population growth and energy demand) where there are inherent uncertainties and data limitations.

In considering this, it should be appreciated that not reflecting a driver is effectively choosing a relationship – if only be default.

[85] For example, a dynamic in Australia appears to be emerging whereby some consumers with solar PV have the impression that their electricity consumption, including their reverse-cycle air conditioners and hot water heaters, must therefore be 'green'. While this perception is likely to be mistaken in many instances given the drivers of marginal grid generation in Australia, it is nonetheless having an impact on consumer energy choices in Australia.
[86] The report, and stakeholder presentation, can be found on the Gas Industry Company website here: http://gasindustry.co.nz/about-us/news-and-events/events/release-of-consumer-energy-options-in-new-zealand-2016-update-by-simon-coates/

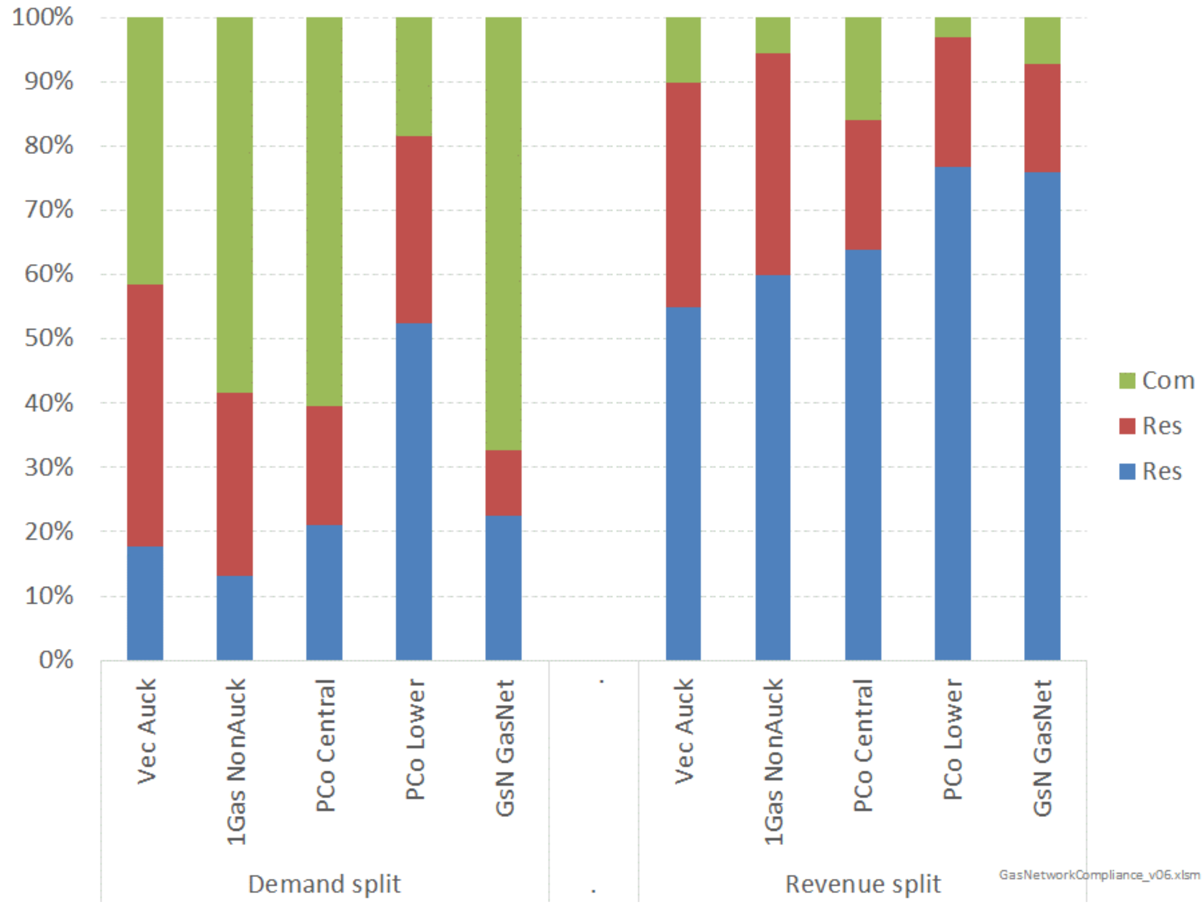
Accordingly, a judgement needs to be made as to whether the scale of error is likely to be greater by not reflecting the driver, rather than attempting to reflect the driver.

With this consideration in mind, a key design objective in developing the structural model for this 2016 demand projections exercise was to reflect:

- The key drivers on different consumer end-uses of gas. Thus:
  - The recent Consumer Energy Options analysis identified that there were significant differences in the relative competitiveness of gas for the main customer end-uses of gas: mass-market space heating, mass-market water heating, and industrial process heat. This relative competitiveness of gas is likely to have a bearing on the future rate of growth of gas for these different end uses.
  - Similarly, population growth is likely to be more of a driver of demand for residential energy in general (i.e. not fuel specific), whereas GDP growth may be more of a driver of industrial energy demand.[87]
- The different customer mixes between the different network areas. Thus:
  - As shown in Figure 86 the proportion of residential, commercial, and industrial demand is very different between the different distribution networks;
  - The proportion of space heating demand is likely to be different on a geographical basis between the (warmer) North and (colder) South.
- The different likely drivers on the demand for energy services in the different network areas – in particular to reflect differences in population growth.

[87] This difference has also been recognised in other analyses, such as the 2012 MBIE study "Changes in Energy Use in New Zealand 1990-2011"

Figure 86: Reported FY15 demand and revenue splits for different consumer segments for different distribution networks



The rest of this section describes the approach adopted to the structural model in a series of high-level steps.

Step 1 – 'Decompose' reported demand into sub-segments

The basis for the projections are the disclosures made by the network companies to the Commerce Commission. These projections were analysed for the five reported distribution networks: Vector Auckland, Vector Non-Auckland (now First Gas), Powerco Central, Powerco Lower, and GasNet.

The disclosures were on the basis of load groups. These were grouped into three main customer segments: Residential, Commercial and Industrial. The assignment of a load group into segments was largely based on the network companies' own classification on such a basis. However, as discussed later, a sensitivity was run where Commercial customer load groups with average ICP demand of above 3,000 GJ/annum (roughly 120 times greater than an average residential customer) were classed as Industrial.

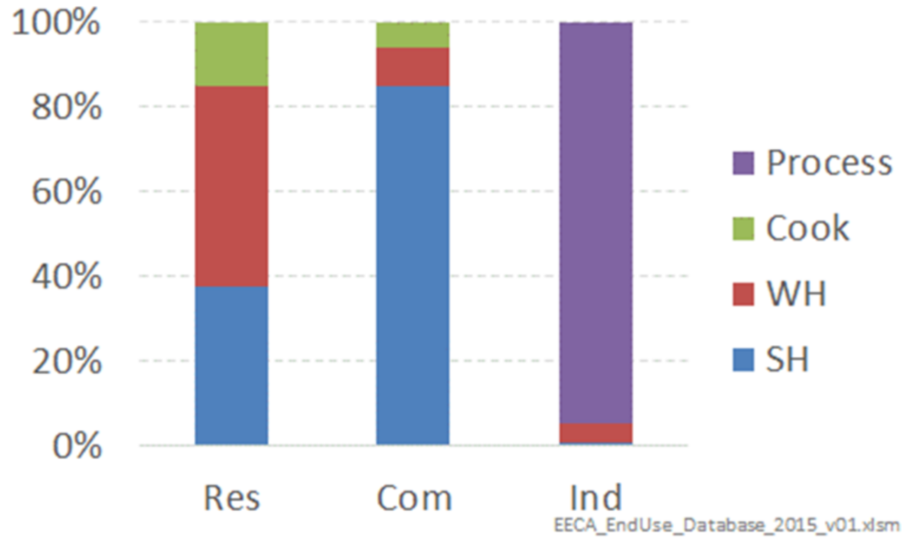
The historical demand analysis shown previously on page 117 gives more information on the different resultant customer segment breakdowns between networks.

Some of the customer segments (i.e. Res, Com, Ind), were then further split into end-use segments as follows:

- Residential: space heating, water heating, and other (largely cooking)
- Commercial: space heating, and other (assumed to be a mix of water heating, cooking and process heat)
- Industrial – no split as largely assumed to be predominantly process heat

Analysis of EECA's energy end-use database was used to estimate the splits. This is illustrated in Figure 87.

Figure 87: EECA estimated splits of gas demand among different energy end-uses for different customer segments



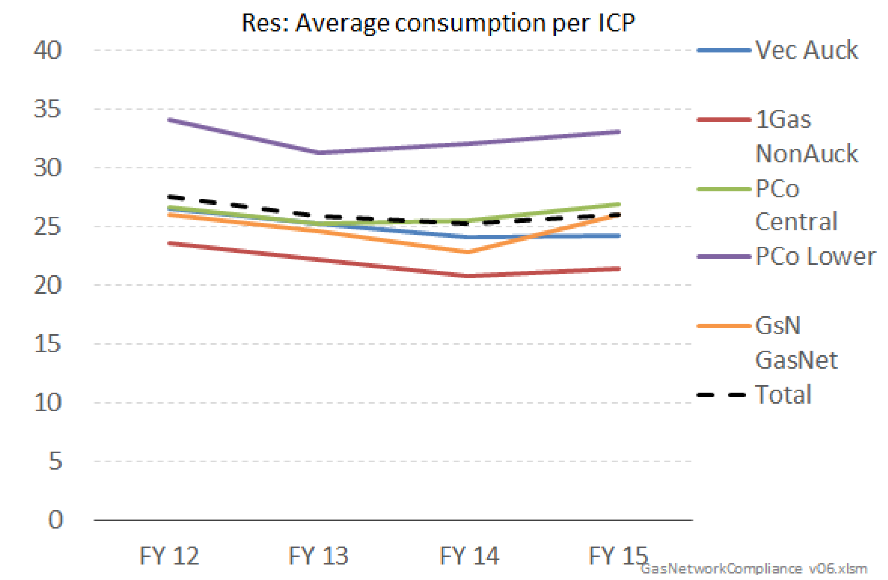
As a cross-check, the residential demand splits aligned reasonably closely with the HEEP data[88] – although this may be because the EECA data referenced the HEEP analysis. However, it is not possible to be certain on this matter.

To account for the fact that space heating quantities are likely to vary between the (warmer) North and (colder) South of the North Island, the residential proportions were applied to the reported average residential energy demand for 2015 across all the networks (26.1 GJ), to derive average values for water heating and cooking. These values were assumed to be constant across the different networks, (i.e. people were likely to use as much hot water in Wellington as in Auckland).

The difference between the reported average FY2015 residential demand per ICP for each network (shown in Figure 88 below) and the sum of the average water heating and cooking demand was used to estimate the likely average space heating demand per residential ICP for each network. i.e. space heating is the 'balancing item' in the equation. Thus, average per customer space heating demand was estimated to be significantly higher for the PCo Lower region, than the 1Gas NonAuck region.

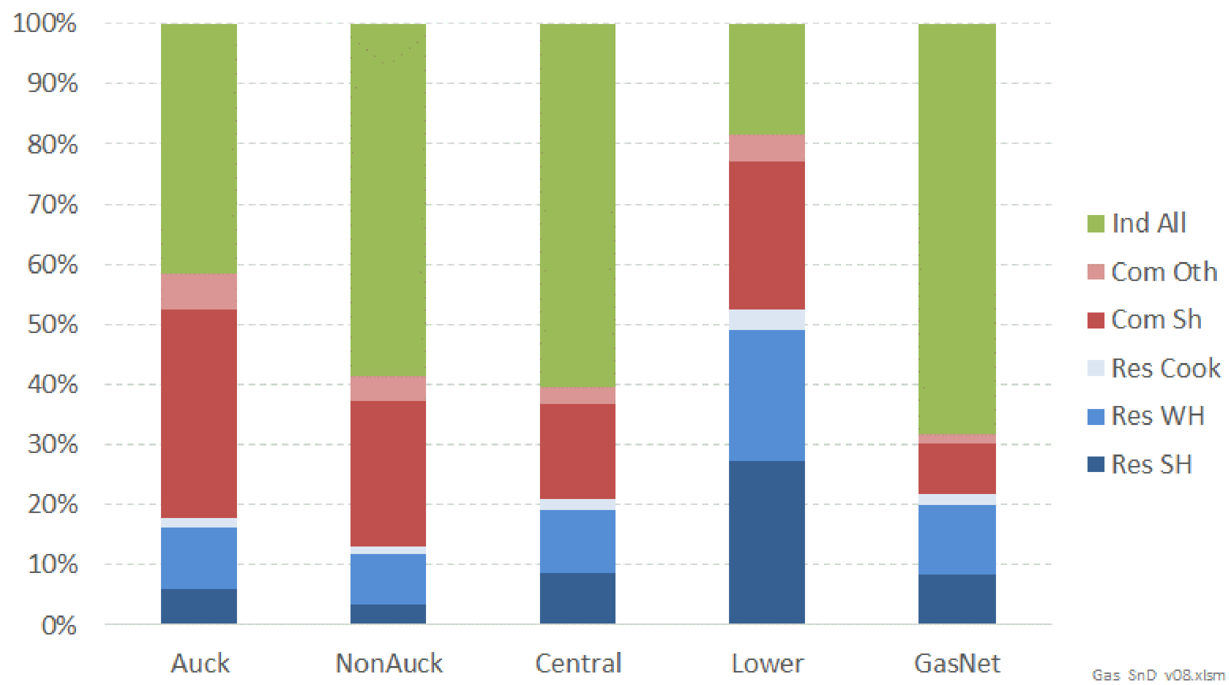
[88] HEEP = Household Energy End-use Project. http://www.branz.co.nz/HEEP

Figure 88: Reported average residential demand per ICP for each network



The resultant break-down of demand into the key end-use segments for the different network areas is shown in Figure 89.

Figure 89: Estimated break-down of FY15 demand into key end-use segments by network area



Because the assignment of load groups into commercial and industrial is likely to result in some commercial consumers being classified as industrial (e.g. hospitals), and some industrial consumers being classified as commercial (e.g. relatively small manufacturing businesses), a sensitivity was undertaken whereby the proportion of commercial space heating demand was varied on a scenario basis. This is detailed later on page 148.

Step 2 – Develop approaches to project demand for these end-use segments

An approach was developed which sought to distinguish between:

- new demand (i.e. new houses, or new businesses or factories requiring energy services); and

- existing demand (i.e. existing houses, business or factories) who have the potential option of switching away from their current fuel and appliance option to another.

This approach was considered important because the Consumer Energy Options study identified that the capital-intensive nature of energy end-uses means that fuel switching is much less likely for existing consumers (who have sunk capital for their existing fuel and appliance option). Further, the effect of energy efficiency is likely to be much greater for new energy users than existing users.

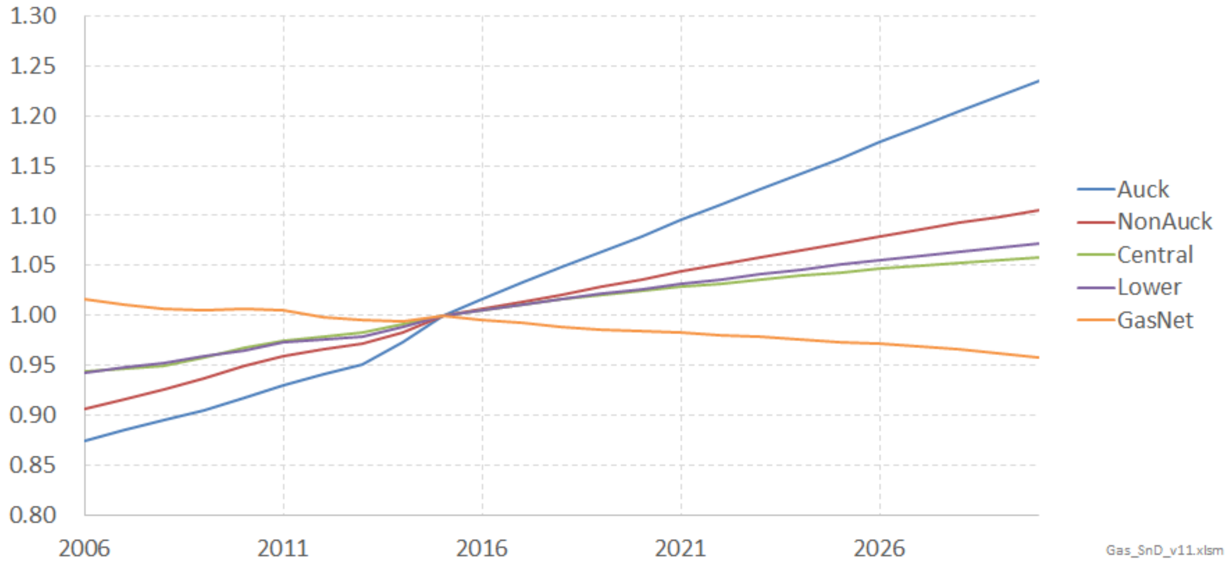
For a given 'decomposed' segment. (e.g. residential water heating), the approach taken to projecting the potential change in demand is as follows.

For new demand:

1) ***Estimate the change in demand for the underlying energy service (i.e. not fuel specific)***. This is based on projections of population and/or GDP, as they are considered to be the key long term drivers of future demand for energy services. The sub-steps of this exercise were as follows.

    a. For population, network-specific projections were developed based on data produced by Stats New Zealand – both historical and Stats NZ projections. To enable estimation at a network level, each district council in the North Island was assigned to a network. The Stats NZ high and low population growth scenarios were used as the basis for the High and Low population scenarios for this exercise. Figure 90 shows the resultant relative projections for the Central scenario. As can be seen, Auckland is projected to continue to have much higher rates of population growth than the other network areas.

Figure 90: Historical and projected rates of population growth for the different networks

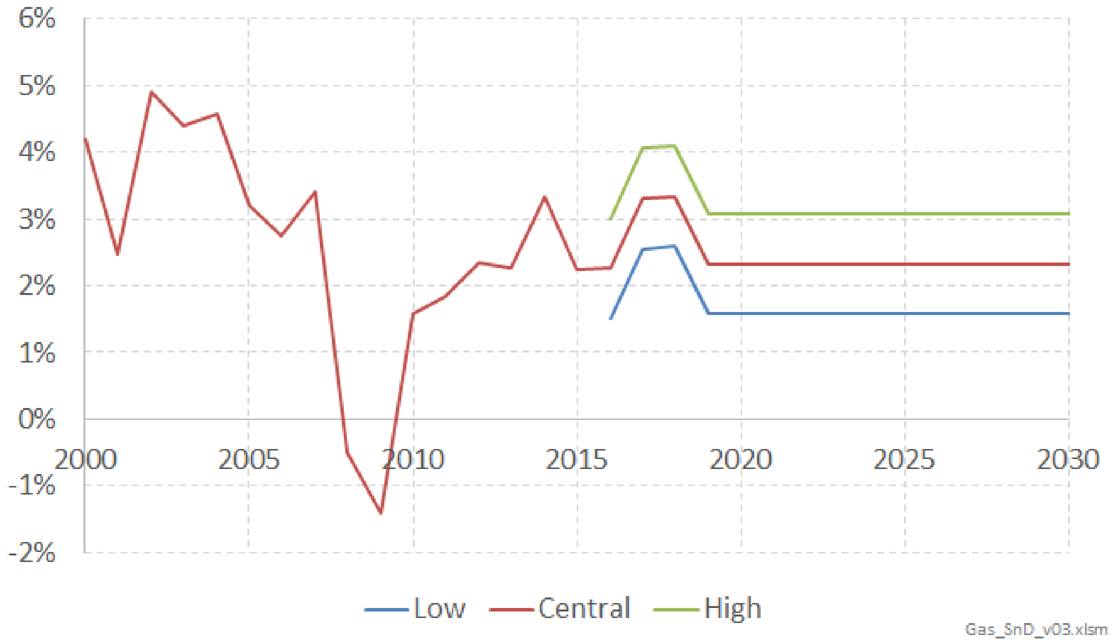


There have been historical changes in dwelling density and house size – both of which will likely impact on residential demand per person. However, these are understood to have been relatively slow-changing variables whose rate of change has reduced in recent years. Accordingly, their potential future impacts have not been explicitly considered for the projections.

There could also be greater variations on a regional basis than is currently suggested by the High and Low scenarios (which have been derived by applying High / Low ratios relative to Central based on the national population projections). Stats NZ also provide specific regional High / Low projections. No investigation has been made as to whether the regional High / Low ratios relative to Central are greater than the national High / Low ratios. However, given there is unlikely to be asymmetry in these High / Low projections, and given the purpose of these projections, it is not considered likely that this would deliver significant additional value.

b. For GDP, the latest Treasury projections to 2019 were used. The 2019 value was projected to continue for the remainder of the projection period. +/- 0.75% values were used for the High and Low scenarios – being Concept assumptions rather than Treasury, given that Treasury does not appear to produce such sensitivities. The resultant projections are shown in Figure 91.

Figure 91: Historical and projected GDP growth rates



c. No data could be readily sourced as to historical and projected rates of GDP growth on a regional basis. However, past work indicates it is likely that there will have been significant regional variations in GDP growth. To the extent such regional variations have occurred, it is likely that this will have affected demand for energy in the different areas.

   Further, it is highly likely that the extent to which GDP growth will be the key driver of energy growth versus population growth will vary between residential, commercial, and industrial demand segments. Accordingly, the following approach has been adopted

   i. For each customer segment, we estimate the relative extent to which Population or GDP is likely to be the best explanatory factor to estimate future demand for energy. Thus for residential demand, population was considered to have a 100% factor, whereas for Industrial it was considered to be 80% driven by GDP and only 20% by population. For Commercial a 70% : 30% population : GDP factor split was used.

   ii. Because GDP projections are only on a national basis, yet it is known that GDP growth varies on a regional basis – with a linkage to population growth – a further factor was developed to simulate the extent to which the *location* of GDP-driven demand growth is influenced by population growth. This assumes that it is likely that a high proportion of GDP-driven Commercial demand growth will be located in areas with a high population growth, whereas a greater proportion of Industrial demand will be located in other areas due to other factor inputs than labour being the key determinant of location.

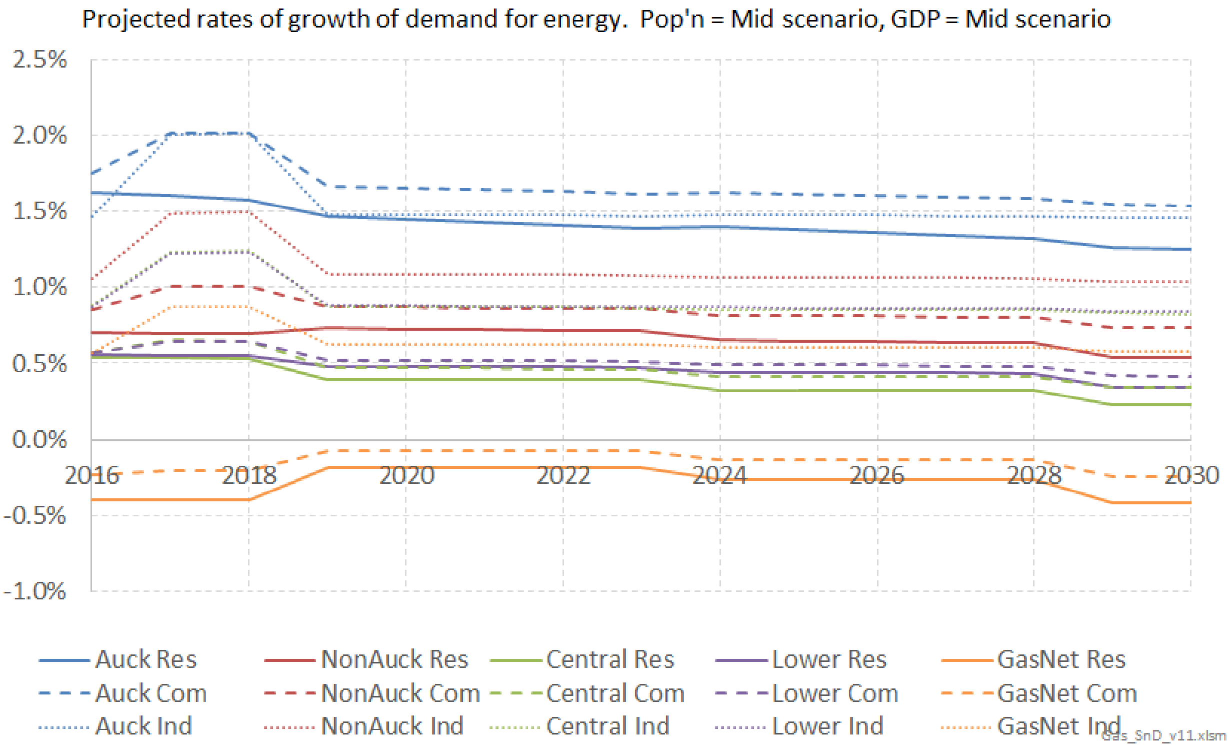
   iii. Lastly, past analysis by MBIE[89] has identified that the energy intensity of business (i.e. commercial + industrial) energy demand growth relative to GDP

[89] *"Changes in Energy Use New Zealand 1990 – 2011"*

growth is such that the rate of energy growth is 50% of the rate of GDP growth. No analysis was undertaken by MBIE as to the extent to which this may vary between fuels. Accordingly, this 50% factor was used to drive the extent to which energy demand is driven by changes in GDP.

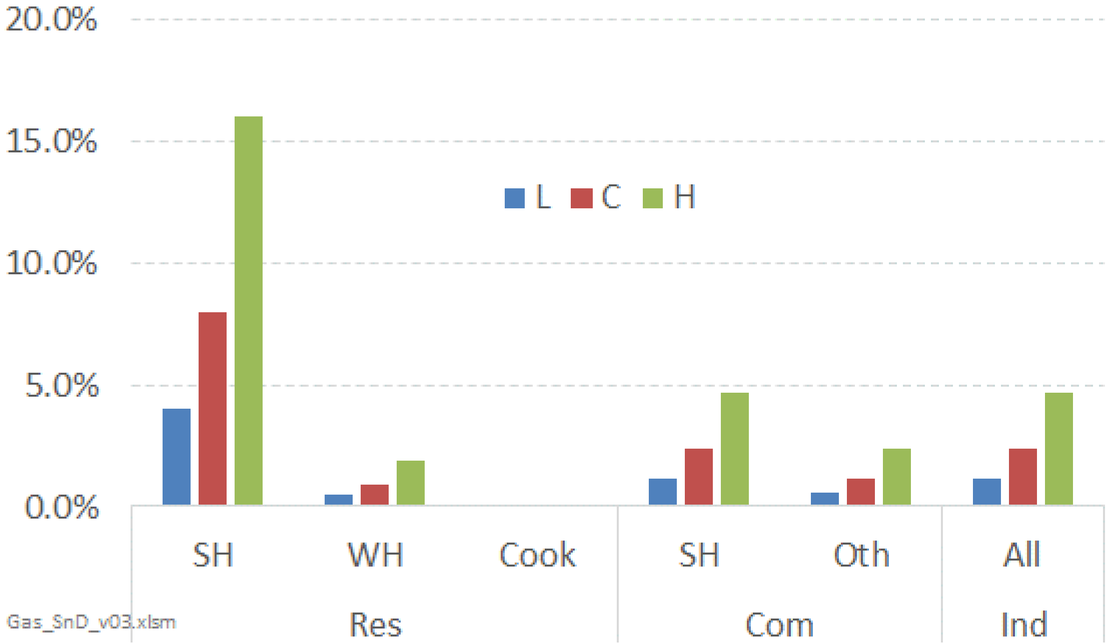
d. The final outcome of all the population and GDP drivers is expressed as a % growth factor. E.g. a factor of 1% for a given year indicates that the underlying demand for the energy service (i.e. not fuel specific) is projected to grow by 1%. The results for the Central projections are shown in Figure 92.

Figure 92: Projected rates of growth of demand for energy. Mid population & GDP growth scenarios



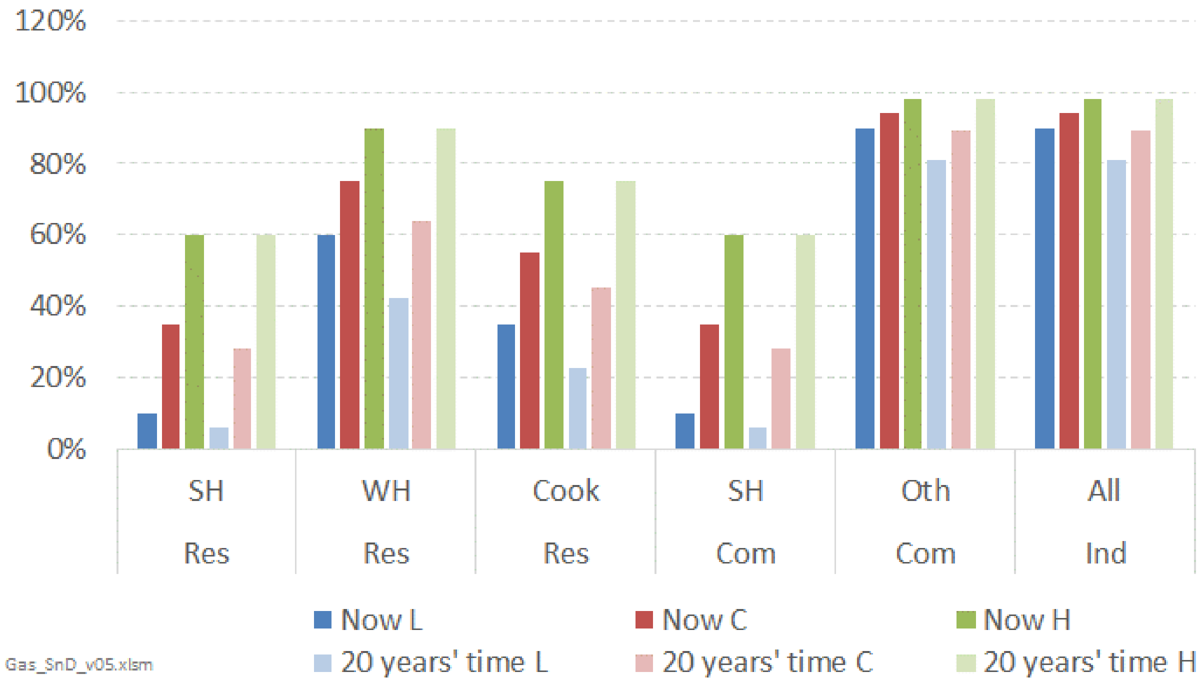
2) ***Estimate the extent to which the servicing of new demand is likely to be more energy efficient than existing demand***. For example, a new house is likely to be better insulated than existing houses (particularly very old houses, but not necessarily much better than those built in the last 15 years), meaning the space heating demand could be substantially less. Likewise, new process heat boilers are likely to have superior efficiency than existing boilers, and the processes using the heat are likely to be more efficient. Conversely, we do not consider it likely that new cookers will be materially more efficient than existing cookers. The estimated values used (and the Low and High sensitivities) are shown in Figure 93 below.

Figure 93: Estimated improvement of energy efficiency of new demand relative to average existing demand[90]



3) ***Estimate the extent to which gas is likely to win this growth in demand for energy services***. The estimates are given in Figure 94.

Figure 94: Estimates of the proportion of gas in meeting growth in the demand for energy services.



As can be seen, these have been developed with Low, Central, and High values, both Now and for 20 years' time. These estimates have been developed based on:

a. The Consumer Energy Options report which looked at the relative competitiveness of gas compared to other fuel choices. This analysis indicated that gas is very strongly

---

[90] In this, it should be noted that a reasonable proportion of existing demand will be for houses and appliances which are relatively new.

competitive for process heat, competitive for mass-market water heating, but less competitive for mass-market space heating (particularly for smaller heating requirements).

b. Consideration of the reported market shares produced by EECA of the different fuels for the different uses as shown in Figure 95 below. In this, it should be appreciated that, as shown in Figure 96 the vast majority of wood and black liquor (and geothermal) use for process heat is concentrated in a few, super-large wood processing industrial sites that are of a size that would be connected to the gas transmission network rather than distribution businesses. Likewise, the coal and electric demand for high-temperature process heat shown in Figure 97 is predominantly for demand that would also be connected to the gas transmission network if it were to be serviced by gas. When these are excluded, gas' market share of existing process heat is much closer to being 90-100%, compared with the relatively low % shares of gas for the residential and commercial end-uses of gas, as shown by Figure 98.

c. Sanity checking the resultant output in terms of what this implies with regards to the growth in demand. In this, Figure 99 indicates that, over the four years of disclosure data, residential gas ICPs have grown at twice the rate of population growth – as indicated by a gradient of 2 for the linear best fit line.[91]

   This residential gas ICP growth rate would suggest that the share of gas for residential sub-divisions is materially greater than the share for the existing population as a whole. This may be a reflection of the fact that population growth is understood to be greatest in urban centres where there are existing reticulated gas networks, and where there is not the legacy of a large number of houses that were developed prior to the start of the Kapuni era of gas (i.e. the mid-1970s) when reticulation started to be rolled-out. This is also consistent with the fact that a very large number of existing properties are 'gas-fronted' (i.e. there is a gas main running along their street) but not connected to the gas network.

   When the estimated water heating success rate in Figure 94 is factored by the estimates of the proportion of customers with gas, the implied rate of growth in connections is similar to the observed rate shown in Figure 99.

   Conversely, for distribution-connected industrial process heat, there is far less scope for gas increasing its market share of new demand *relative* to its market share of existing demand.

d. Consideration that, in the long-term, gas may become relatively less successful / competitive relative to alternative fuel options than at the present. This is due to a number of considerations, particularly:

   i. The fact that there is likely to be ongoing improvements in the cost and performance of heat pumps (space and water) of a scale which is greater than improvements in gas heating technologies. Similarly, some electro-mechanical technologies may start to become viable alternatives to gas for process heat.

   ii. The possibility that the New Zealand energy sector may face a higher price of CO_2 which may result in progressive switching away to less emissions-intensive technologies (e.g. biomass, high efficiency electric heating).

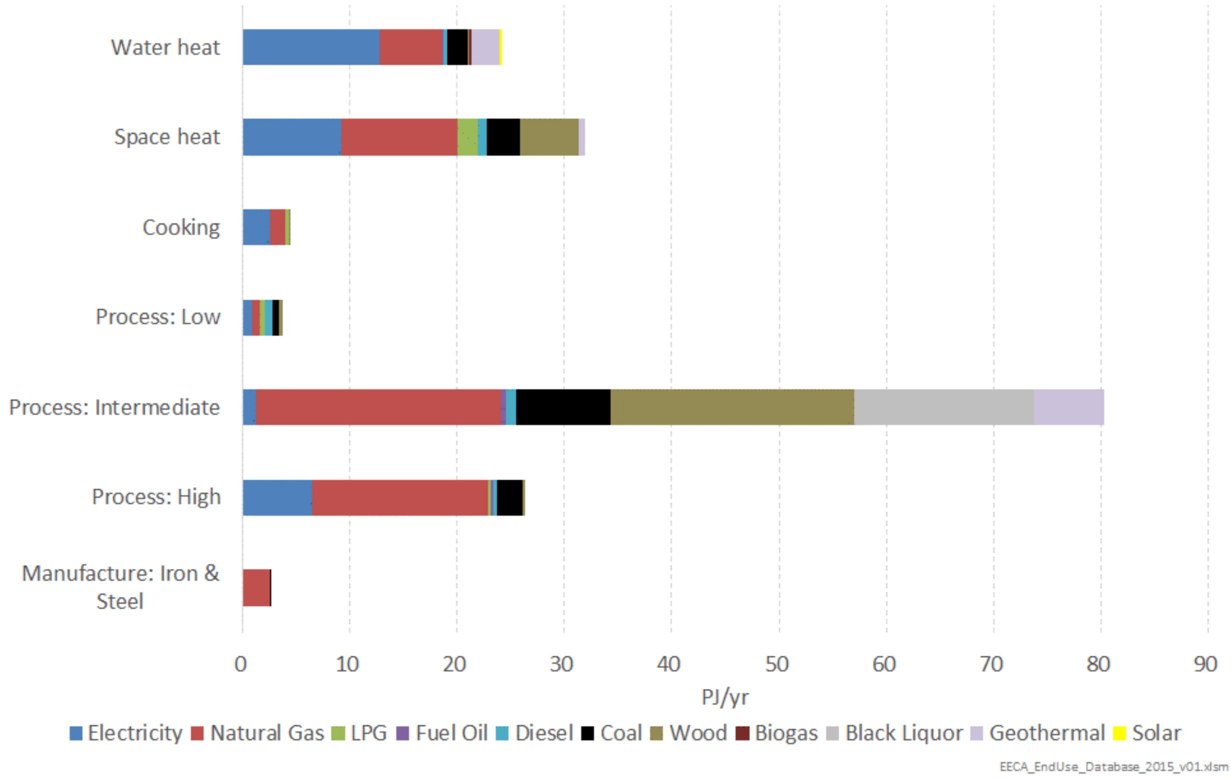
However, it should be appreciated that the estimates shown in Figure 94, have a significant margin of uncertainty, and they are 'best estimates' to attempt to reflect the known dynamics (e.g. gas is relatively more competitive for water heating than space heating) in as consistent a

[91] This compares with past analysis by Concept which indicates that the rate of growth of electricity ICP connections is much more aligned with the rate of growth of population.

fashion as possible. The development of Low and High scenarios with a significant range is an attempt to address such uncertainties.

In this respect, one inherent source of uncertainty relates to possible changes in the structure of electricity prices. The Electricity Authority, and many network companies and other stakeholders, have indicated that such changes are desirable to enable consumers to make optimal technology and consumption decisions. These changes are likely to materially impact on the relative competitiveness of electricity and gas appliances. However, the nature and scale of such changes is highly uncertain – both generally, and on a regional basis.[92] Appendix A of the latest Consumer Energy Options report presents some analysis describing the nature and potential scale of such outcomes.[93]

Figure 95: North Island delivered fuel energy



[92] The impact on gas consumption due to altered electricity pricing could have a significant regional variation due both to possible *future* regional differences in electricity price structures, as well as an observed significant *current* regional variation in electricity price structures.

[93] The report, and stakeholder presentation, can be found on the Gas Industry Company website here: http://gasindustry.co.nz/about-us/news-and-events/events/release-of-consumer-energy-options-in-new-zealand-2016-update-by-simon-coates/

Figure 96: North Island delivered fuel energy for intermediate temperature process heat

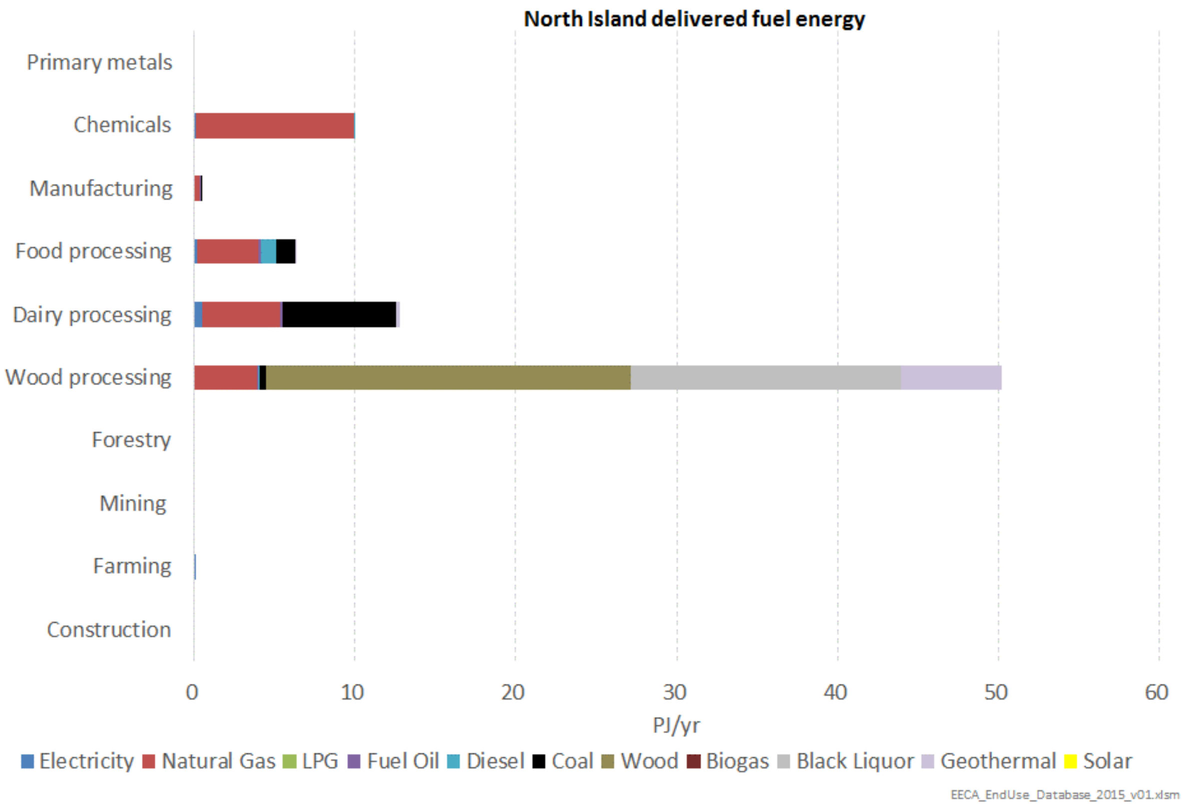


Figure 97: North Island delivered fuel energy for High-temperature process heat

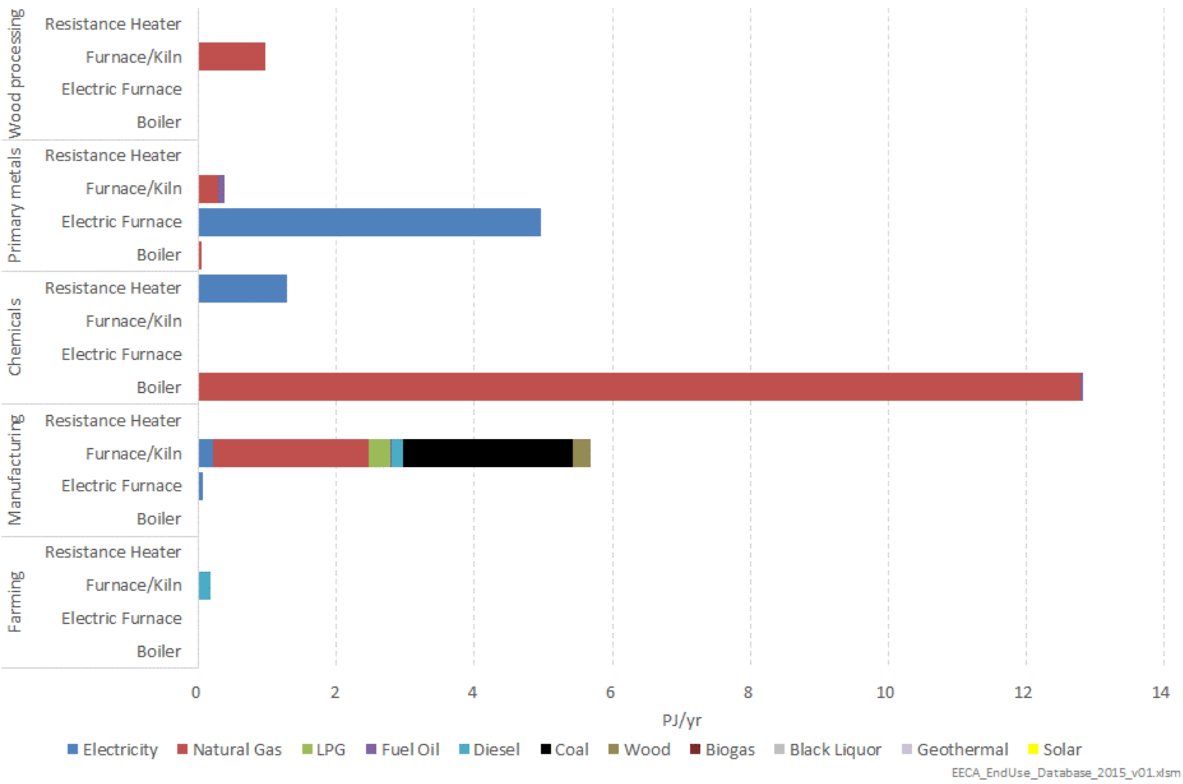


Figure 98: EECA energy end-use database reported shares of gas for residential and commercial energy end-uses

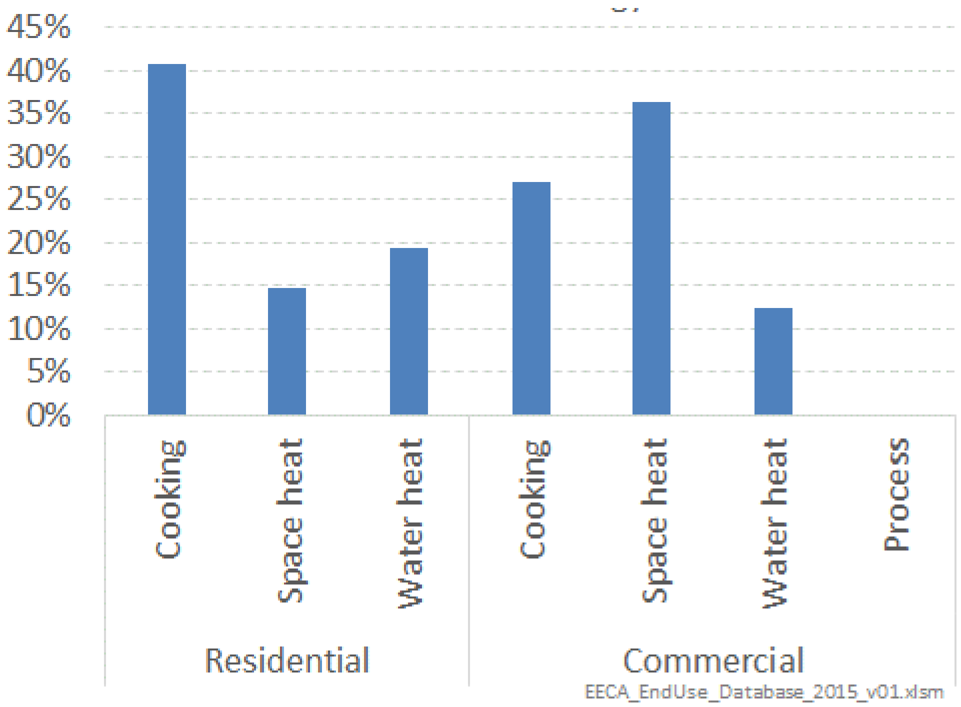
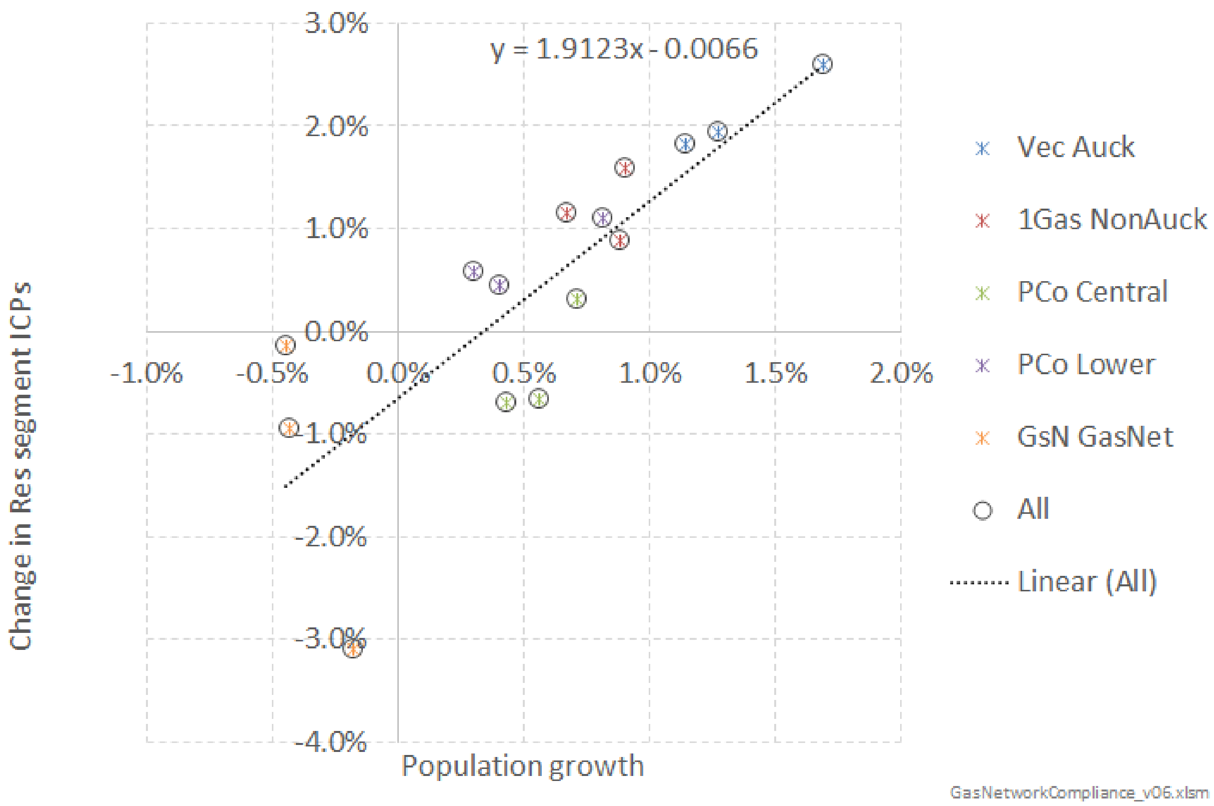


Figure 99: Comparison of residential gas ICP growth and population growth

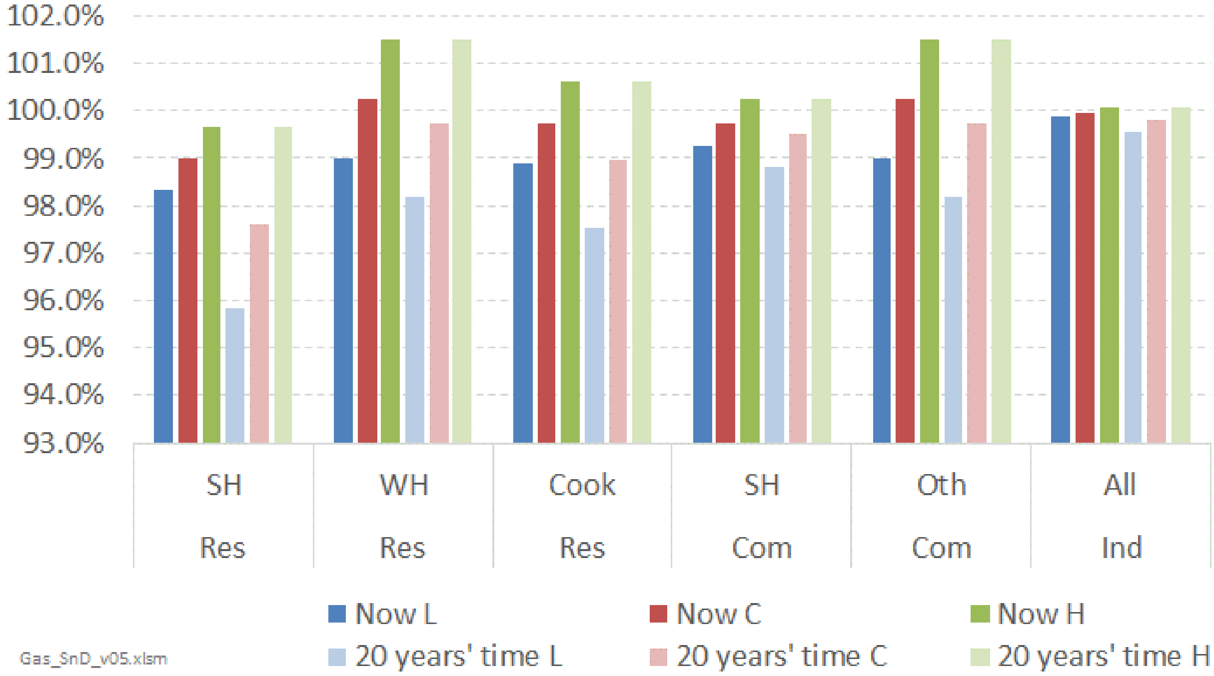


For existing demand:

1) ***Estimate the extent to which there is a fuel switching dynamic to/from gas for existing customers***. The values shown in Figure 100 show the estimated annual change in demand due

to this net effect of customers switching to/from gas, both for the present time, and in 20 years' time.

Figure 100: Estimates of the change in demand for gas for existing customers



An estimate of >100% indicates that there is some fuel switching away from alternative fuels *towards* gas, and vice versa for <100%. These estimates have been developed largely based on the Consumer Energy Options analysis, and considerations of

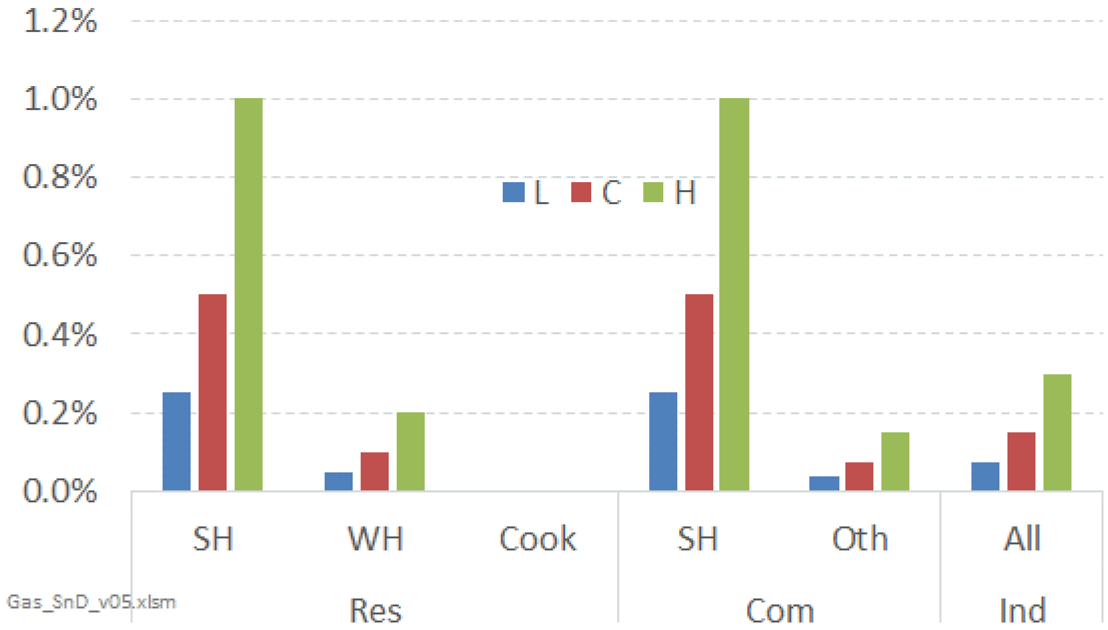
a. the typical capital replacement cycle of the appliances (noting that most fuel switching occurs when such major capital decisions are required);

b. the relative cost-effectiveness of gas versus these alternative options.

c. The extent to which gas may be relatively less successful / competitive relative to alternative fuel options than at the present, and the uncertainty around such future competitiveness, based on the same reasons given in relation to new energy demand on page 138.

2) ***Factor existing demand by an ongoing improvement in energy efficiency.*** The steady improvement in energy efficiency is likely to continue, but the impacts are likely to vary significantly between end-uses. Thus, the opportunities for insulation to reduce space heating demand are considered to be greater than the opportunities to reduce water heating demand. Further, the ongoing improvement in the efficiency of existing demand is considered to be a lot less than the improvement in the efficiency of new demand compared with existing demand shown in Figure 93 previously. The estimates used for the ongoing improvement in existing demand are shown in Figure 101.

Figure 101: Estimated average annual improvement of the energy efficiency of existing demand



Results

Central case assumptions

The following graphs show the projected central-scenario gas demands for the five different network areas, both in absolute terms, and in terms of relative annual movement.

Figure 102: Central projections of annual quantities of gas (TJ). (≤2015 are actuals)

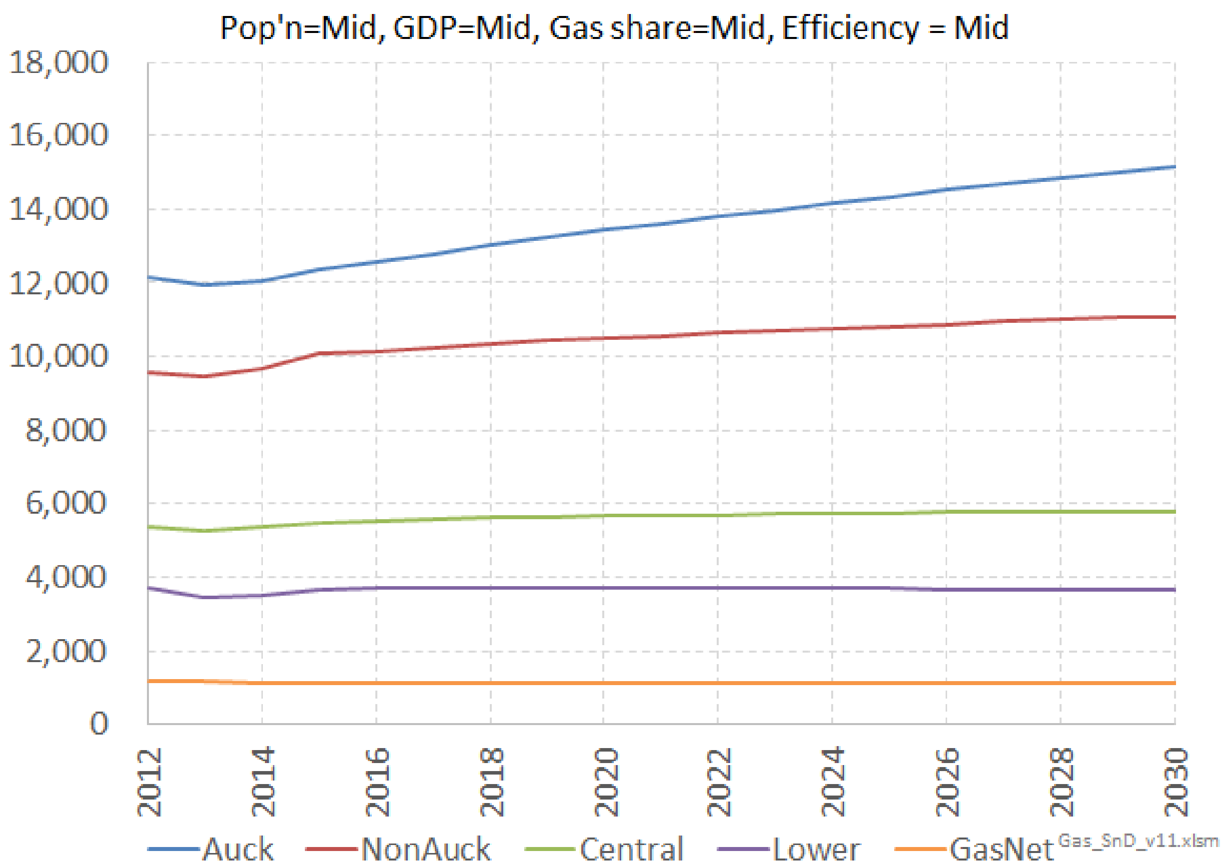


Figure 103: Central projections of rates of change of annual quantities of gas (≤2015 are actuals)

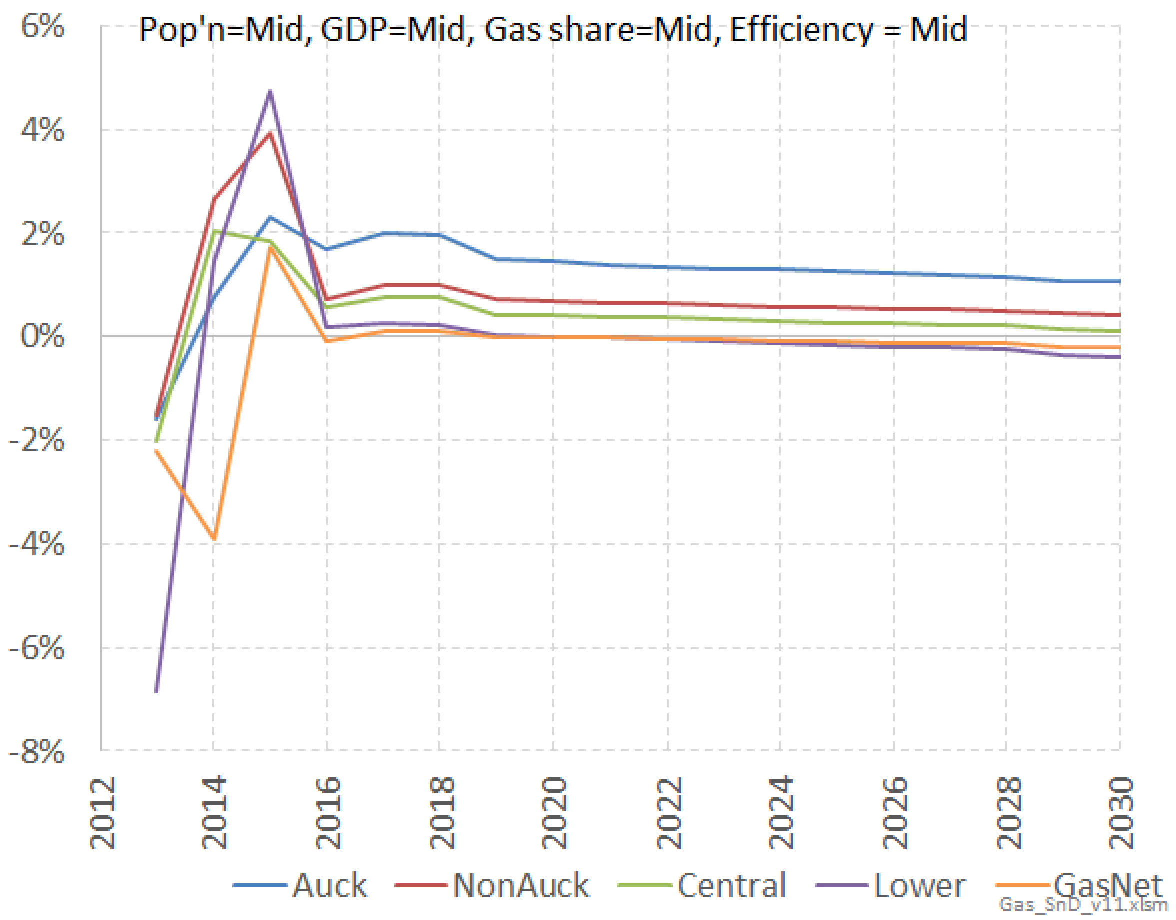
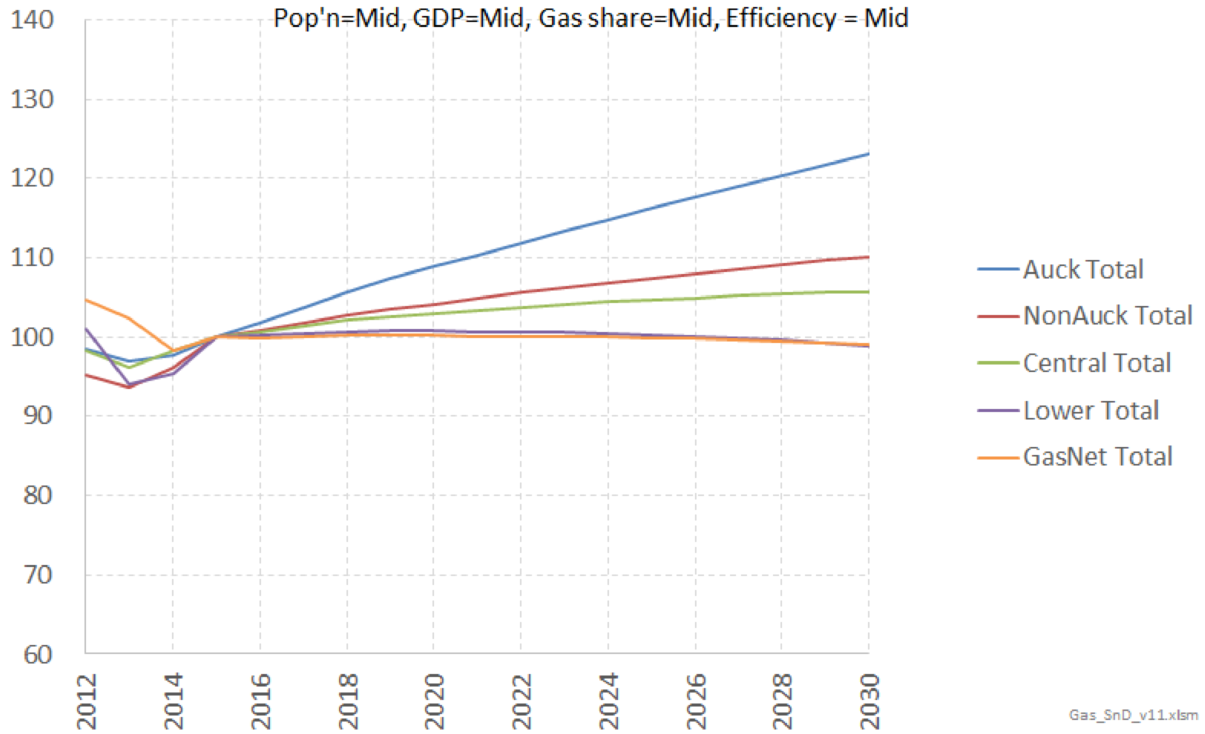


Figure 104: Central projections of relative change in annual quantities of gas (≤2015 are actuals)



The key take-away from the above graphs is the significant difference in projected demand outcomes between the different networks, with much higher projected growth in Auckland compared with the slight long-term decline in the Powerco Lower network.

This difference is principally a function of the following factors:

- Much higher projected population and GDP-related growth in Auckland than in these other networks, as indicated in Figure 90 and Figure 92, previously.
- The different proportions of customer types and end uses, as originally shown in Figure 89, but repeated in Figure 105 below. This is significant because, as is further illustrated in Figure 106, the different types of customer and end-use are projected to have material differences in the success of winning fuel market share from electricity and other fuel options (e.g. wood or LPG). Thus, a network with a high proportion of residential space heating is likely to have reduced demand growth compared to a network with relatively small amounts of residential space heating.

Figure 105: Estimated break-down of FY15 demand into key end-use segments by network area

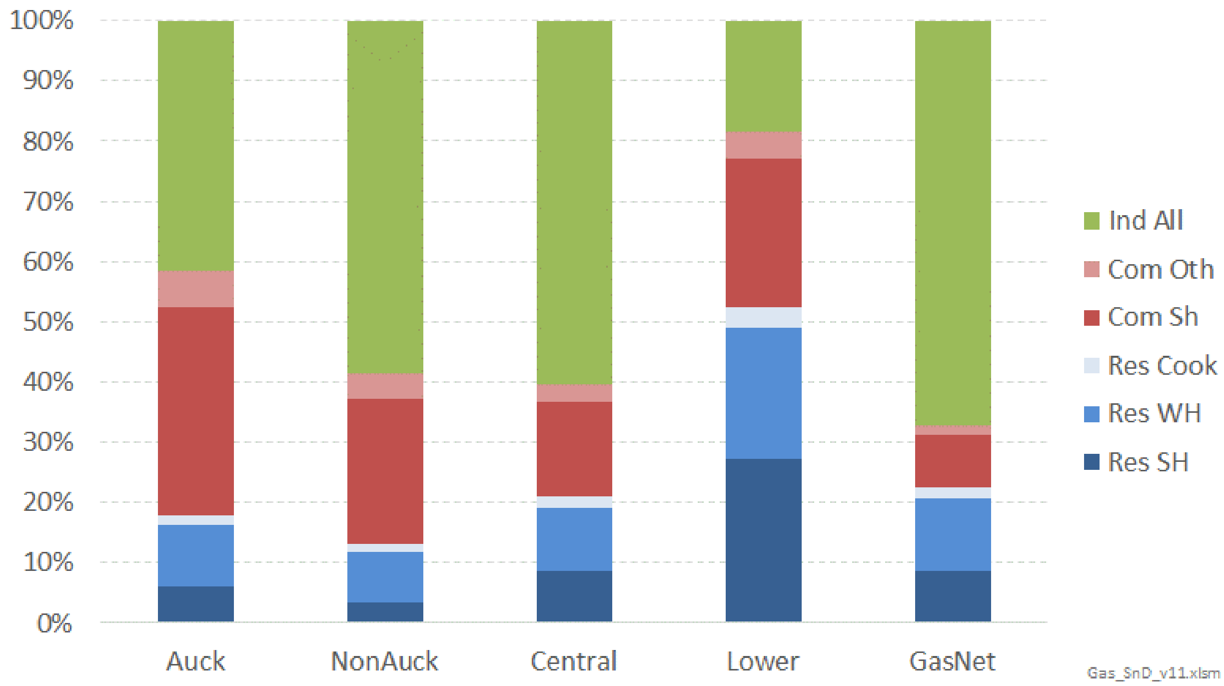


Figure 106: Projected relative change in demand for gas for the key end-use segments

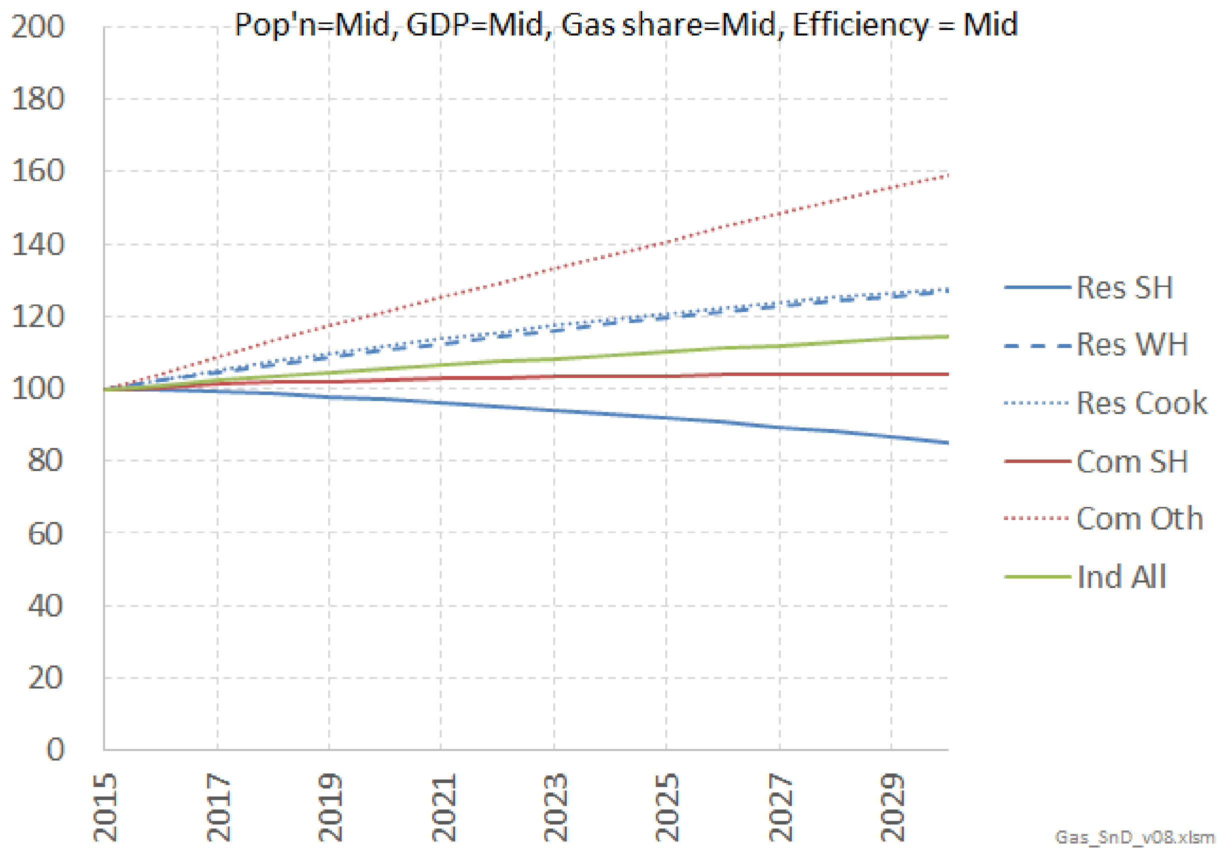


Figure 107 and Figure 108 give two further views onto the projections,

Figure 107: Central projections of relative movement in Residential, Commercial and Industrial demand for the different networks

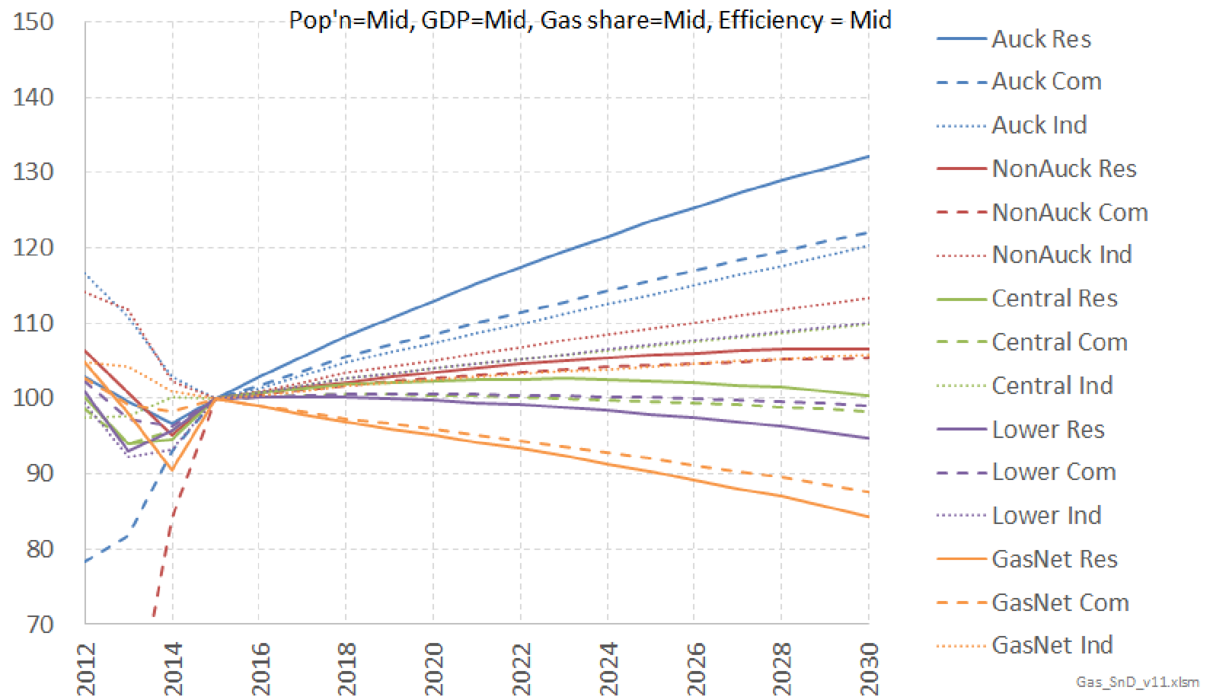
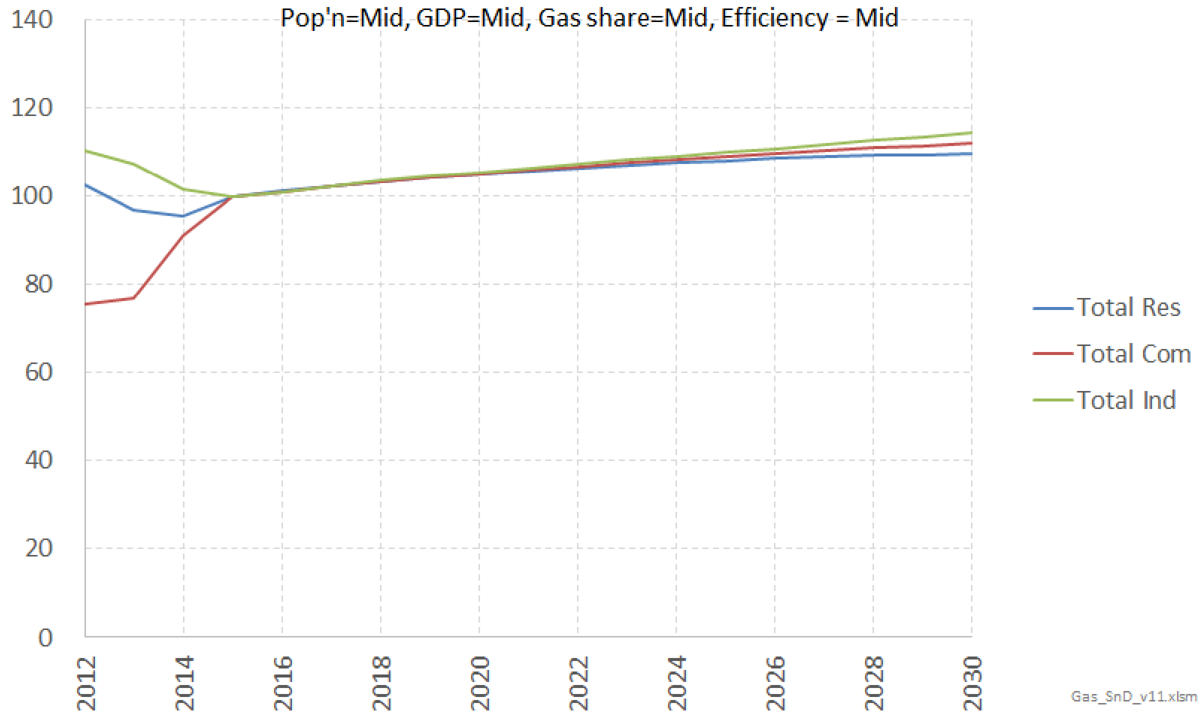


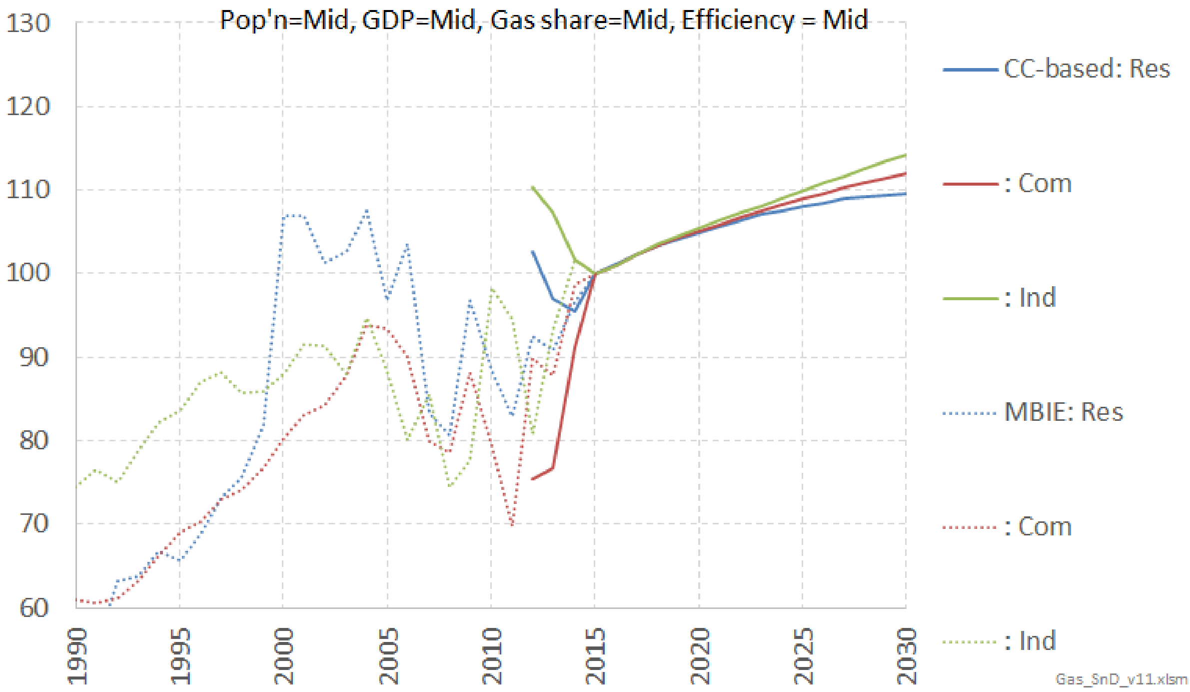
Figure 108: Central projections of relative movement in Residential, Commercial, and Industrial demand summed across all networks



Comparison with historical data series and projections

Further analysis was undertaken to compare the projected movement shown in Figure 108, with historical changes in Residential, Commercial, and Industrial demand over a longer time series as reported by MBIE. This is shown in Figure 109.

Figure 109: Comparison between historical MBIE-reported change in gas demand for different customer segments with projected central-scenario change in demand

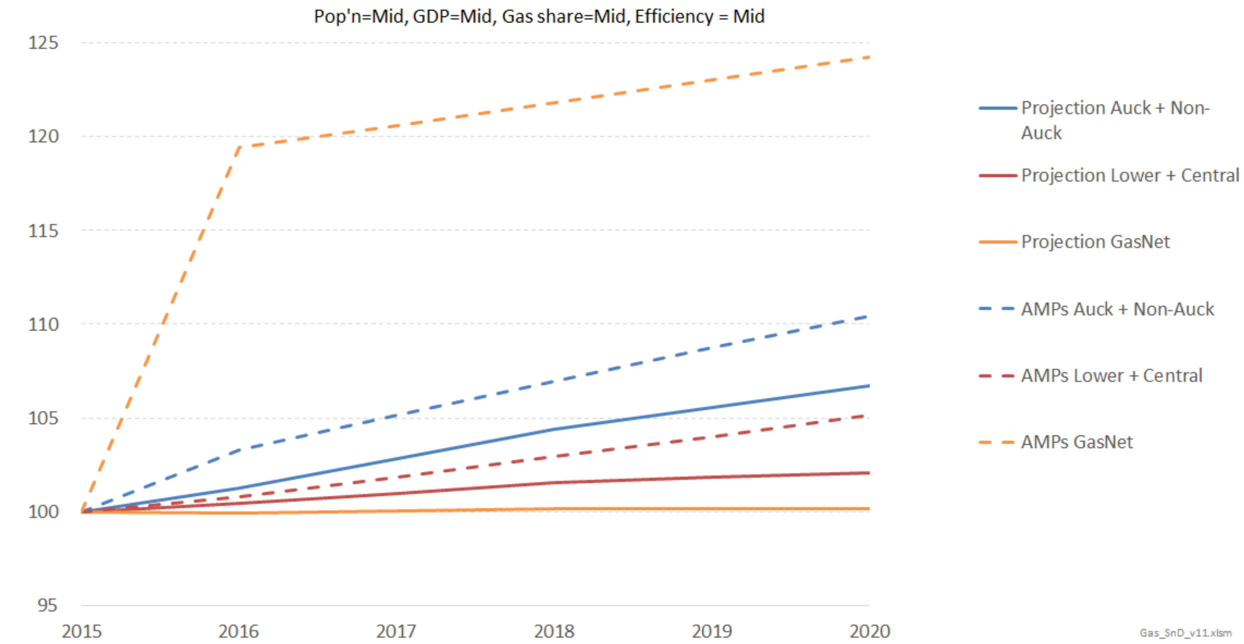


Lastly, comparison was made with the demand projections made in the most recent distribution network asset management plans produced by Vector, Powerco and GasNet. These are not disaggregated by sub-network for Vector and Powerco (e.g. Auck/Non Auck, Central/Lower) or by customer type. The results are shown in Figure ***110***. They appear to indicate that the network companies expect greater demand growth than projected by Concept. Further, the extent to which Concept is 'under-estimating' appears to be consistent between the Vector, Powerco and GasNet. It appears that GasNet is projecting a significant one-off increase in demand between 2015 and 2016. This may be due to a large one-off industrial connection.

This may indicate that Concept's projections are under-estimating the likely growth of gas for the different networks. However, no analysis has been undertaken to understand the underlying factors driving the differences between Concept's projections and the network companies' own projections.

Potentially, some average between Concept's projections and those from the network companies could be used for the Commission's CPRG forecasting.

Figure* 110 *Comparison between Concept central-scenario projections of gas demand growth and network companies' AMP projections



Addressing sensitivities and uncertainties

As has been indicated in the description of the model, there is lack of visibility of much historical data, and inherent uncertainties around future demand drivers. To address this, the model was developed to allow many of these key variables to be altered on a scenario basis – typically, Low, Central and High.

The key factors that were varied on a scenario basis were:

- Population growth (as previously described on page 134)
- GDP growth (as previously described on page 135)
- The extent to which energy efficiency reduces demand for energy services generally (as previously described on pages 137+)
- The extent to which gas wins the fuel switching competition relative to electricity and other fuels (as previously described on pages 137+)
- The proportion of demand which is classed as 'Commercial' space heating (given that the success of gas for space heating is considered to be a lot less than for other commercial uses or industrial

process heat, and there was material uncertainty as to the proportion of commercial demand used for this end use. This was addressed via two sensitivity factors:

  – Altering the classification of load groups in the disclosure data so that a sensitivity was run where Commercial customer load groups with average ICP demand of above 3,000 GJ/annum (roughly 120 times greater than an average residential customer) were classed as Industrial.
  – Varying the proportion of Commercial demand that was assessed to be space heating. As well as using the EECA-derived value of 85%, Low and High sensitivities of 65% and 90% were also used.

- The extent to which demand could be affected by unusual weather. Thus, if a year were relatively warm demand would be less, and vice versa if it were cold. This has been simulated by altering the starting year (2015) values for the demand sub-components (space heating, water heating etc.) by a factor which is intended to capture the likely variance in demand outcomes. This has been implemented at this stage relatively simply through varying 2015 values +/- a fairly simple factor, without undertaking specific analysis on the extent to which 2015 was relatively warm or cold, and the extent of altered demand outcomes that occurred because of that.

  However, the starting historical year quantity is a very important value as, to the extent it was unusually warm or cold, it will result in the subsequent projections being systematically too low or high. This will have significant implications for allowable network revenues under weighted average price cap form of price control. Accordingly, there may be merit in undertaking further work on weather-correcting the starting historical year's demand if these projections are to be used for the purposes of price control.

A Monte Carlo modelling exercise was then undertaken which ran every one of the 1,458 combinations of the above variables.

Analysis was then undertaken on the range of outcomes across these different combination scenarios. The results are presented in the following figures. These indicate that there is a significant range of uncertainty over future gas demand, and that this uncertainty grows over time.

It is likely that greater effort in determining Low and High scenario values could reduce the extent of this uncertainty. However, that was out of scope for this exercise.

It should be appreciated that this sensitivity analysis was relatively simplistic in that it allows the various sensitivities to compound – e.g. perpetual high population and GDP growth, in combination with high gas market share success will progressively compound the effects leading to very high rates of growth, and vice versa for the low scenarios. No analysis has been done to attempt to assign probabilities to the various extremes of outcomes.

Figure 111: Range of projected total annual quantities for the different networks

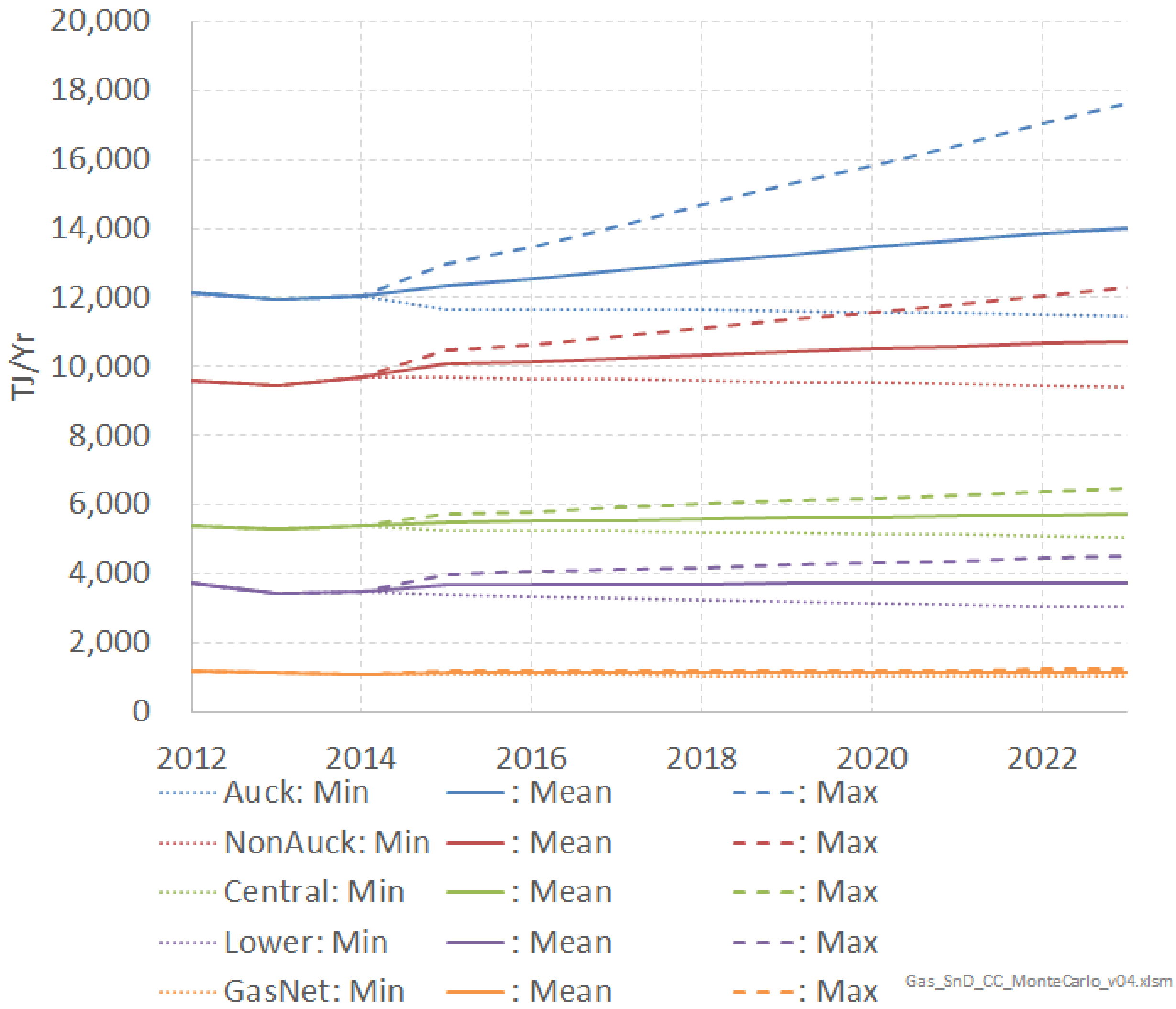
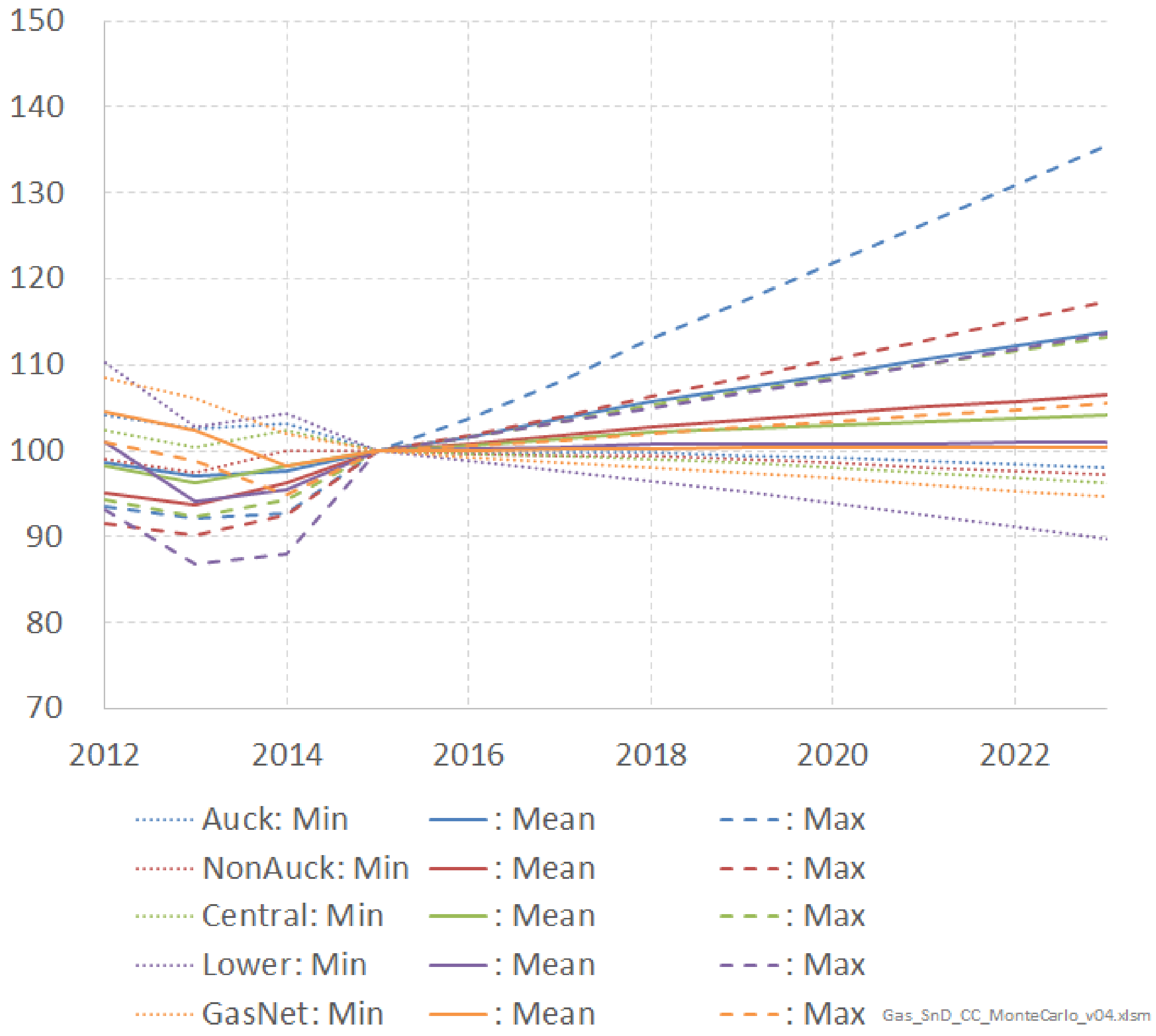


Figure 112: Range of projected rates of change of total annual quantities relative to 2015 for the different networks[94]



[94] The differences in the historical years is because of the sensitivity run looking at varying the 2015 demand to reflect uncertainties in weather.

Figure 113: Range of projected rates of change of residential segment annual quantities relative to 2015 for the different networks