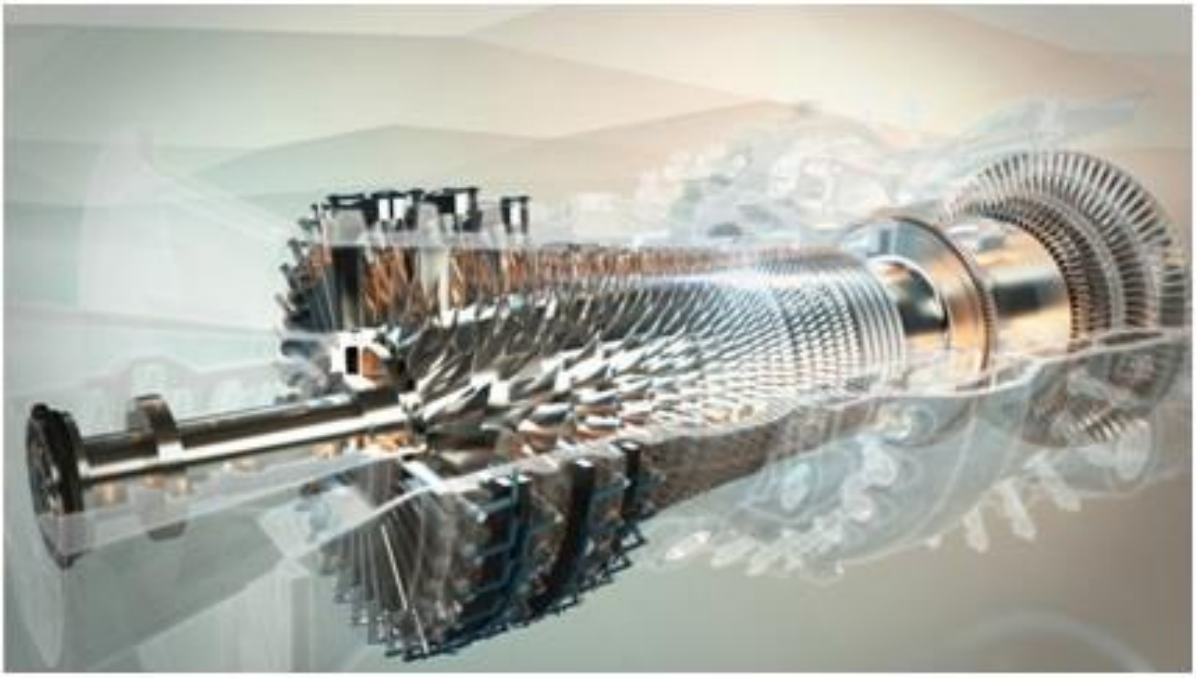
2020 THERMAL GENERATION STACK UPDATE REPORT

PREPARED FOR THE MINISTRY OF BUSINESS, INNOVATION & EMPLOYMENT

29 OCTOBER 2020



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REV	DATE	DETAILS
1	27 July 2020	Draft report
A7	24 Sept 2020	Revised draft report for client review and feedback
A8	29 October 2020	Final report

	NAME	DATE	SIGNATURE
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Our ref: 6-P0192.00

29 October 2020

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Dear Daniel

2020 Thermal Generation Stack Update – Final Report

WSP is pleased to submit this Final Report after receiving your feedback on the draft report.

Thank you for the opportunity to provide this report and we hope it provides a useful update on the current state of the New Zealand thermal generation stack and the future thermal generation developments which are possible.

Regards

L.J. Pepper

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Energy Project Manager / Asset Management Consultant

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GLOSSARY

2-shifting operational mode	A generation unit may ramp up output in the morning peak electricity demand period, reduce output and then ramp up output during the peak evening demand period, before reducing output overnight.
AF	Availability Factor
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CDS	Centralised Data Set
CGPI	Capital Goods Price Index
E&M	Electrical and Mechanical
EA	Electricity Authority
EDGS	Electricity Demand and Generation Scenarios
EOH	Equivalent Operating Hours
EPC	Engineering, Procurement and Construction
ETS	Emissions Trading Scheme
FDC	Fixed Direct Costs
FOM	Fixed Operations and Maintenance Costs
GEM	Generation Expansion Model
GJ	Gigajoules
Gross (and Net)	In this report, and consistent with general electricity industry practice, the terms “gross” and “net” are reserved for discriminating between electricity generation measured at the generator terminals (gross) and at the high voltage, transmission line side of the generator step-up transformer (net). Net generation is also commonly called “sent-out” and “dispatched” generation. The difference between the two is the electricity consumed in-house (auxiliary or parasitic load) and internal transformer losses.
GT	Gas Turbine

GW	Gigawatt
GWh	Gigawatt-hour
GXP	Grid Exit Point
Heat rate	A measure of the efficiency of the fuel-to-electricity conversion process in terms fuel quantity in energy terms consumed (burned) for each unit of electrical energy produced. The MBIE have defined this parameter as "for each GJ of Fuel input how many useful (station export) GWh of electricity are generated". Note that GJ/GWh = MJ/MWh = kJ/kWh, the latter being the more common units. Whenever heat rates are expressed, they must be accompanied by the qualifications 'net' or 'gross' and 'HHV' or 'LHV", i.e. Net Heat Rate = 9180 kJ/kWh (HHV). MBIE have asked for the HHV heat rates to be provided in this report.
HFO	Heavy Fuel Oil
HHV	Higher Heating Value (HHV) or equivalently Gross Calorific Value (GCV) is a measure of the specific energy content for a fuel and is determined by bringing all the products of combustion back to the original pre-combustion temperature, and in particular, condensing any vapour produced. HHV are used to determine the actual amount of fuel that would need to be purchased to produce a MWh of electricity. This report only displays heat rates using HHV. To avoid confusion with Gross and Net generation output (inclusive or exclusive of parasitic load within a generation station), the term GCV is not used in this report.
HRSG	Heat Recovery Steam Generator
IDC	Interest During Construction
IEA	International Energy Agency
kV	Kilovolt
LHV	Lower Heating Value (LHV) or equivalently Net Calorific Value (NCV) is a measure of the specific energy content for a fuel and is determined by subtracting the heat of vaporisation of the vapour produced in combustion of a fuel from the Higher Heating Value (HHV). LHV is not used in this report.
LNG	Liquefied Natural Gas
LRMC	Long Run Marginal Cost

MCR	Maximum Continuous Rating
MBIE	Ministry of Business, Innovation & Employment
MVA	Megavolt-Ampere
MW	Megawatt
MWh	Megawatt-hour
NCF	Net Capacity Factor
Net	In this report, and consistent with general electricity industry practice, the terms “gross” and “net” are reserved for discriminating between electricity generation measured at the generator terminals (gross) and at the high voltage, transmission line side of the generator step-up transformer (net). Net generation is also commonly called “sent-out” and “dispatched”. The difference between the two is the electricity consumed in-house (auxiliary or parasitic load) and internal transformer losses.
NOF	Net Output Factor
O&M	Operations and Maintenance
OCGT	Open Cycle Gas Turbine
ORC	Organic Rankine Cycle
pf	Pulverised Fuel
SOO	Statement of Opportunities
ST	Steam Turbine
TJ	Terajoules
ULP	Unit Largest Proportion
VOM	Variable Operations and Maintenance Costs
WSP	WSP New Zealand Ltd.

EXECUTIVE SUMMARY

The Ministry of Business, Innovation and Employment (MBIE), with support from Transpower, has engaged WSP New Zealand Ltd (WSP) to review and update the thermal generation component of the "Generation Stack". The Generation Stack is a list of existing and potential future electricity generation projects in New Zealand. There is a need to update the Generation Stack database to ensure that the information is current and as accurate as possible so that any modelling based upon it is robust and delivers reliable results.

The Generation Stack is used by MBIE in the development of Energy Sector and Climate Change policies – and also by Transpower to help identify potential future transmission grid constraints and/or to identify where the grid may need to be strengthened to accommodate new generation growth. The future of the New Zealand (NZ) electricity system has been the focus of many studies in recent years with reports undertaken by Transpower, the Interim Climate Change Committee, MBIE (Ministry of Business, Innovation and Employment) and the Productivity Commission being the most noteworthy. These reports address the growth of NZ's electricity market (out to 2035 in the ICCC report and to 2050 in the other reports) and what this means in regard to NZ's electricity demand - and mix of technologies - as it moves towards a 100% renewable generation goal and a low carbon economy. A key consideration will be the role thermal generation plays in the future.

This report only focuses on the **Thermal** electricity generation plants in New Zealand. The past WSP report covered all forms of generation including also Hydro, Wind and Geothermal.

MBIE has a need to update this thermal generation dataset to ensure that:

- the information used to compile the EDGS is up-to-date and fit-for-purpose.
- a robust and up-to-date evidence base is used for developing energy sector and climate change policies.
- the information is useful for the wider modelling community.

Since the last report was completed in 2011, a number of thermal generation plants have now been retired. These include Southdown and Southdown E10, Otahuhu B and Huntly Unit 3. This reflects the changing New Zealand electricity market, fuel markets and the push for New Zealand to have more renewable energy supplied to the national grid. There have been a few new thermal plants commissioned during this period which are included within this report. These include Bream Bay Peaker, McKee and Junction Road.

Due to a number of factors, it is expected that there will continue to be a retirement of existing thermal generation units over the next 10 years. So careful planning will be required to ensure grid security and generation supply

Projected electricity demand growth in the New Zealand is currently expected to continue to steadily grow, with increased demand in the northern areas. Some new thermal generation plants are likely to be constructed and will most likely be peaker units, fuelled by natural gas, as long as the reliability of this gas supply can be maintained. Within this report WSP has noted new emerging technologies within the thermal generation sector, which may utilise alternative zero carbon emission fuels and give increased location options for thermal generation plant. More cogeneration options may also become energy and power options for large industrial energy users around New Zealand.

1 PROJECT BACKGROUND

1.1 PURPOSE OF THIS REPORT

MBIE is responsible for preparing the Electricity Demand and Generation Scenarios (EDGS), which contain projections of future electricity demand and generation in New Zealand. Doing so requires MBIE to maintain detailed information on existing and planned new electricity generation plants in New Zealand. This reference information, known as the "generation stack", includes information on the technology, size, location, and costs of running each plant.

The generation stack is used by MBIE, Transpower, the Electricity Authority, and others involved in the New Zealand electricity industry, to assist with understanding and determining what electricity generation capacity is required to be built, and when, in order to meet forecast electricity demand.

The last comprehensive update of New Zealand's generation stack was undertaken in 2011 by Parsons Brinckerhoff[1] (referred to from hereon as "the WSP report"), for the then Ministry of Economic Development. This report update project has been awarded to WSP which has previously acquired the Parsons Brinckerhoff organisation into the wider WSP global organisation. This report has been created primarily using experienced team members from the WSP NZ Power Team. MBIE only required an update of the previous report, rather than a completely new report.

MBIE has a need to update this dataset to ensure that:

- the information used to compile the EDGS is up-to-date and fit-for-purpose.
- a robust and up-to-date evidence base is used for developing energy sector and climate change policies.
- the information is useful for the wider modelling community.

The purpose of this project is to produce an updated assessment of thermal electricity generation in New Zealand out to 2060. This includes an update of information on existing grid-connected thermal generation plants, as well as the provision of information on potential new generic plants. "Thermal" for the purposes of this project refers to those plants that are fuelled by coal, natural gas, and/or oil products (such as diesel).

1.1.1 HOW TO USE THIS DOCUMENT

WSP has been engaged by MBIE to provide an update of technical and cost data for existing and potential future thermal electricity generating plant in New Zealand. This reference document and data set is primarily intended to support energy supply scenario forecasting performed by MBIE.

The Generation Expansion Model (GEM) is a tool used for new generation build forecasts such as those previously produced and published by the Electricity Commission in the Statement of Opportunities (SOO) work stream. As a result of past electricity market reforms, MBIE now has responsibility for maintaining information on the costs of new and existing generation in New

[1] Parsons Brinckerhoff (2012). 2011 NZ Generation Data Update. A report for the Ministry of Economic Development https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-publications-and-technical-papers/nz-generation-data-updates/

Zealand. The reference information provided in this Report is a key input to the modelling performed using GEM (a model maintained by the Electricity Authority).

The reference data set provided within this Report which comprises technical and cost data estimates for generating plant with an operational capacity of greater than 10MW is split into three main categories or report sections:

- Existing NZ thermal generating plant (Section 3).
- Proposed NZ thermal generating plant (Section 4).
- Future generic NZ thermal generating plant (Section 5).

The proposed plant dataset (contained in Section 4) covers selected project(s) that have been identified by MBIE as having, at the time of writing, either applied for resource consent, have had consent granted or are generally considered to be most likely to be built in future.

Section 5 provides guidance on possible future generic types of generating plant and estimates the technical and cost parameters required by the GEM. As part of this work a list of possible future generic projects has been provided which is intended to represent the range of plant indicative of the future build options over the modelling timeframe (out to 2060) and provides the GEM with an option list to build and forecast future electricity supply scenarios. The list is not a view or opinion of what will actually be built over the modelling period or what type of plant has a greater probability of being built.

Absolute values are provided in this Report in response to the GEM data requirements. It is important to note that the cost estimates provided in this report are WSP's opinion based on publicly available information, currently available technology and other assumptions such as exchange rates and are the product of a concept or desktop level of estimation. This level of estimation accuracy supports the Report's objective to provide indicative estimates to help MBIE establish the relativity of costs of generation between the different types of plant. This level of estimation for generating plant typically involves an accuracy range of +/- 30%, highlighting the importance of detailed investigations and studies when evaluating specific projects given that technical and cost parameters of power projects are extremely project-specific.

In addition to the data set in Sections 3 to 5, Sections 6, 7 and 8 provide some guidance on possible ranges of high-level plant cost components, commentary around the future drivers of plant cost uncertainty and some additional information relating to the effects of load on thermal plant heat rates.

1.1.2 BACKGROUND

WSP has been engaged by MBIE to provide an update on technical and cost data for existing and potential future electricity generating plant in New Zealand. This data is primarily intended to support energy supply forecasting performed by MBIE.

The GEM is the tool used for new generation build forecasts such as those previously produced and published by the EA in the SOO work stream. As a result of past electricity market reforms, MBIE now has responsibility for maintaining information on the costs of new and existing generation in New Zealand. The information provided in this Report is a key input to the modelling performed using the GEM (a model maintained by the EA).

1.1.3 MBIE MODELLING

The input data included in this report is to be used in the GEM model and for estimating the Long Run Marginal Cost (LRMC) of new generation. The outputs of the GEM model include forecasts of new generation build by fuel/technology type. MBIE also uses the GEM outputs to forecast wholesale electricity prices (based on the LRMC of the new plant built).

MBIE also publishes an "LRMC interactive tool" on its website which would use the information included in this report.

1.2 PROJECT SCOPE

The scope of work for this report comprises four main tasks:

- Task 1 – A review and update of existing New Zealand thermal generation plant information held by MBIE.
- Task 2 – A review and update of proposed New Zealand thermal generation plant information held by MBIE.
- Task 3 – Provision of information on the cost estimates of potential future thermal generating plant in New Zealand.
- Task 4 – Additional discussion on aspects of the key drivers of future thermal generating plant in New Zealand.

1.2.1 TASK 1 – EXISTING THERMAL GENERATION PLANT REVIEW

Information currently held by the MBIE on existing thermal generating plant has been reviewed by WSP. This has primarily involved validating/verifying the information with existing generating plant owners and with publicly available information such as that contained on generator websites or in company annual reports. In some cases, the most recently updated plant information has been included in this report, up until the date of issue.

1.2.2 TASK 2 – PROPOSED THERMAL GENERATION PLANT REVIEW

Information currently held by the MBIE on proposed thermal generating plant has been reviewed by WSP. This has primarily involved validating/verifying the information with the generator most likely to develop the proposed plant, and with publicly available information such as that contained on generator websites or in company annual reports.

1.2.3 TASK 3 – POTENTIAL FUTURE THERMAL GENERATION PLANT

This task involves providing information for possible future thermal generating plant in New Zealand, with an estimated capacity of greater than 10 MW.

In addition to these known/publicly announced projects, WSP has provided commentary on a range of future generic thermal generating plant.

This information is to ensure that there is a broad evidence base available for wider modelling purposes, and is not an indication of policy direction, nor endorsement or otherwise of any technology.

Although it is not expected that a significant amount of new thermal generation will be built in the future, some may be required in order to ensure electricity security of supply. It would be expected that any such plant would be fuelled by natural gas. In the future there may also be opportunities for new technologies and fuels to provide grid security services.

It is possible that new thermal plants could incorporate carbon capture and storage (CCS) technology. As a result, MBIE has asked for the expected cost of new natural gas plants both with and without CCS technology.

1.2.4 TASK 4 – ADDITIONAL DISCUSSION

This task includes the following additional report discussions:

1. Uncertainty of costs: A commentary and analysis on the uncertainty of thermal generating plant cost estimates presented in Task 1 and 2.
2. Heat rate as a function of plant capacity utilisation: For selected thermal plant analysed in Tasks 1 and 2, WSP has estimated the heat rate (Higher Heating Value - HHV) based on an optimum operating range. For various sized projects of each thermal combustion technology, the report provides a spectrum of heat rates relative to a spectrum of capacity utilisations.

   Future uncertainty in costs of new thermal generation: A general discussion on key drivers of uncertainty around future costs for selected generation types.

1.3 PROJECT METHODOLOGY

WSP's approach was based on developing an updated version of the previous piece of work carried out by WSP in 2011 (known as PB at the time, who were bought by WSP in 2014). For NZ's Thermal Generation Stack, there have been a number of changes to this portfolio since 2011 which need to be captured. There have also been changes to the availability and costs of the core fuel supplies such as diesel, natural gas and coal, which also need to be captured. The approach also researched information on potential new thermal generation plants with or without CCS technology and possible Hydrogen fuelled units in NZ.

A variety of information sources were included to gather the existing information and provide the updated generation stack report. Reference sources included:

- Published studies, magazines, articles and reports by WSP and others.
- Information from NZ generators, developers and owners of assets through consultation included as part of the project delivery.
- Third party proprietary information sources to which WSP has access such as GT Pro.
- Channels of communication through existing relationships with OEMs and industry contractors.
- Bloomberg Clean Energy Finance information portal.
- WSP local and global in-house data, knowledge and experience.

Where possible WSP has used a combination of publicly available and third-party information to support the estimates provided.

1.3.1 WSP OPINION

WSP is a leading provider of power generation related engineering services and a strategic asset management adviser to government agencies, developers, owners and operators of plant in New Zealand and abroad. WSP has used its power industry experience and knowledge to review and provide an opinion on the likely technical advancements and cost forecasts for NZ's future generating plant fleet.

The costs provided in the report will represent WSP's opinion on what is a most likely figure given current market conditions, publicly available information and available technology.

1.3.2 CONSULTATION

The following companies were consulted with via a series of brief, targeted video-conference discussions with the aim of updating the information base and reference dataset for analysis.

- Genesis Energy (www.genesisenergy.co.nz)
- Contact Energy (www.contactenergy.co.nz)
- Trustpower (www.trustpower.co.nz)
- Todd Generation Taranaki (www.toddgeneration.co.nz)
- Oji Fibre Solutions (www.ojifs.com)

Given that the above generators were to be asked to provide what might be perceived as potentially sensitive information, the approach needed to enable as much support and openness from the generators as possible. WSP's methodology was based on the successful approach employed for previous similar pieces of work, which included:

- Discussions with Generators, including setting out and gaining agreement from all parties of the approach and timelines.
- Allowing generators latitude to present the information in a format and to a level they were comfortable with.
- Where Generators believed technical and specific cost data to be commercially sensitive and confidential, with their agreement and where possible, WSP would instead refer to generic estimates and use data ranges to inform the estimation process.
- Internal peer reviews completed at key stages of the project.
- Generators invited to carry out reviews of the report sections concerning them.
- Generators invited to give some indications of where they believed future thermal generation options existed.

1.3.3 SOURCES / REFERENCES

In preparation of this report WSP has aimed to specify all sources / references and provide explanations for any assumptions and calculations. These references are noted in Appendix A – Bibliography.

1.4 LIMITATIONS

1.4.1 MATERIALITY/ESTIMATION ACCURACY

WSP has provided a range of values for some of the data items included in the scope of work. The ranges provide an upper and lower bound for 'typical' values considered to be normally experienced given the information available today. Where possible and required, WSP has also recommended absolute values for use in MBIE's modelling.

For the cost estimates provided in this Report including plant capital and O&M cost values, WSP has used a target 'concept' level of accuracy of +/-30%.

1.4.2 CONFLICTS OF INTEREST

WSP is not aware of any conflicts of interest arising from or influencing the information contained within the report.

1.4.3 OTHER

Actual energy/fuel cost information is excluded from the scope of work for this report. We have not conducted any market modelling of future NZ supply scenarios as part of the analysis for this report. The focus of this report is on the current technical and cost parameters for generation plant in New Zealand and not an economic analysis or prediction of what plant will be built in the future.

1.5 REPORT STRUCTURE

Section 1 – Project Background

Section 2 – Definitions

Section 3 – Thermal Generation Asset Information Update

Section 4 – Future Proposed Thermal Generating Plant Data

Section 5 – Future Generic Plant Data

Section 6 – Plant Component Cost Breakdown

Section 7 – Thermal Plant Heat Rate vs Utilisation

Section 8 – Uncertainty in Estimating Future Plant Costs

Section 9 – About the Authors

2 DEFINITIONS

The information data set provided by MBIE for WSP to review contains a list of data items and values. To provide some background and a framework for the review, definitions of the more technical data items are included in this report section.

All costs included in this report are quoted in 2020 New Zealand Dollars (unless otherwise specified) and represent a 'most likely' cost given the high level of uncertainty of estimating at a 'concept' level.

Generally, data estimates provided in this report are averages for the project lifetime of the plant in accordance with the GEM information requirements and the nature of the modelling performed by MBIE.

2.1.1 PLANT CAPACITY

There are four commonly quoted capacity values for thermal generation plant which are:

- Gross capacity (MW) – The total installed capacity or nameplate rating of the plant.
- Net capacity (MW) – This is equal to the gross capacity of the plant less any plant auxiliary loads (in MW) and represents the exportable capacity out to the Grid.
- Peak capacity (MW) – the maximum output that the unit or plant is able to produce at any one time. This may exceed the nameplate capacity in some instances.
- Operational capacity (MW) – long term average maximum capacity of the plant.

2.1.2 OPERATIONS AND MAINTENANCE COSTS

These are the ongoing costs associated with the running of thermal generating plant which exclude any capital costs but may include financing costs. The operations and maintenance (O&M) costs for thermal generating plant have been split into two categories, fixed and variable.

2.1.2.1 FIXED O&M COSTS

These are O&M costs which do not vary with the level of generation and are generally influenced by or are proportionate to the size of plant (MW capacity). Theoretically these costs would still be incurred even if the plant was not generating (but still available to generate). Examples of fixed O&M costs include:

- Insurance.
- Landowner costs.
- Some maintenance costs.
- Grid/connection charges.
- Financing costs.
- Communications.
- Corporate overheads/management time.

These costs are expressed on a $/kW/year basis.

2.1.2.2 VARIABLE O&M COSTS

These are O&M costs which are impacted by the level of generation (MWh), i.e. as generation varies, so does the level of costs. Examples of common variable O&M costs are:

- Transmission charges.
- Royalties.
- Some maintenance costs (e.g. periodic maintenance checks based on generation).
- Consumables.

These costs are expressed on a $/MWh basis. Fuel costs are not included as these are scenario-independent inputs that are treated separately by MBIE in its modelling suite.

2.1.2.3 AVAILABILITY FACTOR

The Availability Factor (AF) is defined as the proportion of time that generating plant is available over the time period. Plant is generally unavailable due to two main types of event, planned and unplanned outages. For example, where a plant consists of one 100MW unit, and is available to generate for eight hours out of a ten-hour time period (and hence unavailable for two hours due to either planned or unplanned outages or some combination of the two), the AF is 80%.

For this report which is concerned with average level of plant availability over its lifetime, WSP has not considered the impact of de-ratings or the effects of individual unit unavailability unless specifically mentioned. Given the high level nature of the estimates it is not possible to tell for a plant with an 80% AF whether the whole plant was available for 80% of the time or if the plant comprised two units, whether one unit was available 60% of the time and the other 100%.

2.1.2.4 NET OUTPUT FACTOR

The Net Output Factor (NOF) is defined as the net actual generation (in MWh) divided by the product of the time period (in hours) when the plant is available and the operational capacity in (MW) and is a measure of the average loading in MW terms on the units over the period when the plant is available. For example, for a 100MW plant that generated 400 MWh over a 10 hour period, where the plant was available for only 8 of the 10 hours, the NOF is calculated as:

- 400MWh/ (8 hours * 100MW) = 50%.
- By way of comparison the Capacity Factor for the same example is 400MWh/ (10 hours * 100MW) = 40%.

The NOF can also be calculated by dividing the Capacity Factor by the Availability Factor. Note that it is not possible to tell whether a 50% NOF on a 100MW unit means that:

- The unit ran at 50MW for 100% of the time plant was available.
- The unit ran at 100MW for 50% of the time plant was available.
- Some other combination of loading regime.

For all existing thermal plant WSP has based the estimates on existing levels of generation, information provided by Generators and industry lifetime averages for the level of thermal generation associated with the generic type of thermal plant.

For all proposed or generic future thermal plant, the NOF is based on an estimate of average annual generation over the life of the plant. Where possible, WSP has provided references to publicly available information about the potential level of generation from the plant. Where none was available the estimate is generally based on a set of assumptions relating to the type of plant (technology), resource availability and anticipated plant role (e.g. baseload, intermediate, peaking).

2.1.3 PLANT CAPITAL COSTS

Capital costs have been estimated for proposed and future generic plant. There are a number of factors which can materially influence the estimation of capital costs for generating plant, including the particular specified technical or commercial requirements, origin of the equipment sourced for the project, market conditions at the time of bidding and currency exchange rates applicable at the time of implementation.

Plant capital costs typically include:

- Mechanical (e.g. turbines, generators).
- Electrical (e.g. transformers, switchgear).
- Civil (e.g. buildings, earthworks).
- Engineering design.
- Legal and financial costs including interest during construction.
- Land and consenting costs.

Fuel delivery and lines connection costs are covered by a separate data item in this report.

Estimated plant capital costs included in the Report are expressed on a cost per kW basis, where the Gross capacity (MW) should be used for the calculation of total capital costs for a plant.

Plant capital costs for proposed plant have been quoted in two components:

- A NZD per kW component which represents that portion of the total plant capital cost which is denominated in the local currency, NZD.
- A foreign currency per kW component, where the currency represents the dominant foreign currency for the supply of the non-NZD denominated plant costs e.g. USD.

To arrive at a total capital cost in NZD per kW, both components must be summed with the foreign currency denominated component converted at an assumed exchange rate.

To confirm the accuracy of the data set with the available reference information where no split of local and foreign component has been provided WSP has used the following cross rates using the average foreign exchange rates from XE.com at the time of this report.:

- 1 NZD = 0.68 USD
- 1 NZD = 0.57 EUR
- 1 NZD = 0.51 GBP
- 1 NZD = 0.92 AUD
- 1 NZD = 72 JPY

2.1.3.1 LAND COSTS

Land that is acquired for the purposes of constructing generation assets is subject to restrictions which impact significantly on its value, these include:

- Treaty of Waitangi.
- Offer back obligations for land that has been compulsory acquired.
- Use of conservation land or land used for recreational use and is not to be built on.

Given the accuracy level of plant capital cost estimates provided in this Report, land costs are assumed to be included in the values provided, although no specific land related acquisition costs have been estimated by WSP.

2.1.3.2 RESOURCE CONSENTS

Obtaining consents to build new, expand or modify existing generation or extend the consent period of thermal generating plant can be time consuming and expensive. There is also a possibility that such consents may not be granted in part or fully. Estimating the costs associated with obtaining resource consents is inherently difficult and therefore has the potential to vary considerably from actual project costs.

Given the concept accuracy level of plant capital cost estimates provided in this Report, consent related costs are assumed to be included in the values provided, although no specific consenting costs have been estimated by WSP.

2.1.4 PROJECT LIFETIME

This is the generation technology dependant expected operational or engineering lifetime of a project. This is different from typical economic lifetime values which are typically shorter at 20 or 25 years and are used for assessing the financial or commercial viability of generation projects.

It is the expected operational or engineering lifetime values of generation projects which are included in this report.

3 THERMAL GENERATION ASSET INFORMATION UPDATE

3.1 THERMAL GENERATION SCOPE

This report section provides the WSP technical and cost estimates and describes the process used to review and update the GEM information for existing NZ thermal generation plant. The thermal generation section begins with a summary table of recommended values and then contains a description of the analysis completed for each main data item provided.

A list of plants considered to be in scope for this Thermal Generation Stack Update are shown in the table below. This includes existing plants, with the proposed plant listed below covered in Section 4.

Table 3-1 Thermal Generation Plant Summary

Plant	Capacity (MW)	Fuel Type	Operator
Existing			
Bream Bay Peaker	9	Diesel	Trustpower
Edgecumbe	10	Natural Gas	Nova Energy
Glenbrook	112	Coal/Gas Waste Heat	BlueScope
Hawera (Whareroa Power)	68	Natural Gas	Fonterra/Nova Energy
Huntly Unit 5	385	Natural Gas	Genesis Energy
Huntly Unit 6	48	Natural Gas/Diesel	Genesis Energy
Huntly Units 1, 2 & 4	750	Natural Gas	Genesis Energy
Junction Road	100	Natural Gas	Todd Generation Taranaki
Kapuni	25	Natural Gas	Nova Energy
Kinleith	40	Wood/Gas	Oji Fibre Solutions
Mangahewa	9	Natural Gas	Nova Energy
McKee	100	Natural Gas	Todd Generation Taranaki
Stratford	210	Natural Gas	Contact Energy
Taranaki Combined Cycle	377	Natural Gas	Contact Energy
Te Rapa	44	Natural Gas	Contact Energy
Whirinaki	155	Diesel	Contact Energy
Proposed			
Waikato Power Station	360	Natural Gas	Todd Generation Taranaki

For each of the plants, MBIE's interest is in information about the ongoing costs and life of these plants. MBIE would like to know the following information for each plant:

- Expected major refurbishment work – both timing (year) and associated costs ($ million in 2020 dollars).
- The expected decommissioning year of the plant. This is based on the plant reaching its physical end-of-life. It is not based on criteria such as forecast wholesale electricity prices, or potential climate change restrictions.
- An update of the fixed operating and maintenance (O&M) costs included in the WSP report, expressed as $/kW/year. Rather than a plant-by-plant review, this information has been updated by plant technology and fuel.
- An update of the variable operating and maintenance costs (O&M) included in the WSP report, expressed as $/MWh. Rather than a plant-by-plant review, this information has been updated by plant technology and fuel.

3.1.1 THERMAL GENERATION PLANT SUMMARY

The following table has more detail on the thermal generation plant considered within this report.

Table 3-2 Thermal Generation Plant Details

Plant	Capacity (MW)	Fuel type	Plant Type	Commissioned	Operator	Service Type
Bream Bay Peaker	9	Diesel	Reciprocating Engine	2011	Trustpower	Peaking
Edgecumbe	10	Natural Gas	Cogeneration - OCGT	1996	Nova Energy	Base / Production
Glenbrook	112	Coal/Gas Waste Heat	Cogeneration – Steam Turbine	1997	BlueScope	Base / Production
Hawera (Whareroa Power)	68	Natural Gas	Cogeneration – Steam Turbine	1996	Fonterra/Nova Energy	Base / Production
Huntly Unit 5	385	Natural Gas	Combined Cycle Gas Turbine (CCGT)	2007	Genesis Energy	Base Load
Huntly Unit 6	48	Natural Gas/Diesel	Open Cycle Gas Turbine (OCGT)	2004	Genesis Energy	Base Load
Huntly Units 1, 2 & 4	750	Natural Gas	Coal/Gas Steam Turbine	1983	Genesis Energy	Base Load
Junction Road	100	Natural Gas	Open Cycle Gas Turbine (OCGT)	2020	Todd Generation Taranaki	Peaking
Kapuni	25	Natural Gas	Cogeneration - OCGT	1998	Nova Energy	Base / Production

Plant	Capacity (MW)	Fuel type	Plant Type	Commissioned	Operator	Service Type
Kinleith	40	Wood/Gas	Cogeneration – Steam Turbine	1998	Oji Fibre Solutions	Base / Production
Mangahewa	9	Natural Gas	Reciprocating Engine	2008	Nova Energy	Peaking
McKee	100	Natural Gas	Open Cycle Gas Turbine (OCGT)	2013	Todd Generation Taranaki	Peaking
Stratford	210	Natural Gas	Open Cycle Gas Turbine (OCGT)	2010	Contact Energy	Peaking
Taranaki Combined Cycle	377	Natural Gas	Combined Cycle Gas Turbine (CCGT)	1998	Contact Energy	Base load
Te Rapa	44	Natural Gas	Cogeneration - OCGT	1999	Contact Energy	Base / Production
Whirinaki	155	Diesel	Open Cycle Gas Turbine (OCGT)	2004	Contact Energy	Peaking
Waikato Power Station	360	Natural Gas	Open Cycle Gas Turbine (OCGT)	(proposed)	Todd Generation Taranaki	Peaking

Table 3-3 Existing Thermal Generation Plant Data Summary

Plant name	Plant Technology Type	Energy Type	Substation	Project Lifetime (Years)	Capacity (MW)	Availability Factor (AF) (%)	Unit Largest Proportion (ULP) (%)	Baseload (Y/N)	Heat Rate (HHV) (GJ/GWh)	Variable O&M (VOM) (2020 NZD $/MWh)	Fixed O&M (FOM) (2020 NZD $/kW/yr)	Fuel Delivery Costs (FDC) ($/GJ)
Taranaki CC	CCGT	Gas	SFD	50	377	85	100	Y	7,400	5.2	41	0.44
Huntly unit 5 (e3p)	CCGT	Gas	HLY	50	385	93	100	Y	7,400	5.2	41	-
Huntly gas units 1, 2 & 4	ST	Gas	HLY	50	735	83	33	Y	10,900	9.6	70	-
Huntly unit 6 (P40)	OCGT	Gas/dies el	HLY	42	48	87	100	Y	10,525	9.7	19	-
Huntly coal units 1, 2 & 4	ST	Coal	HLY	50	711	78	33	Y	10,900	11.6	82	-
Kapuni	Cogen	Gas	KPA	42	25	85	100	Y	-	5.1	41	-
Hawera (Whareroa)	Cogen	Gas	HWA	42	68	85	25	Y	-	5.1	19	-
Te Rapa	GT	Gas	TRC	42	44	85	100	Y	11,700	4.9	35	0.79
Kinleith	Cogen	Various	KIN	50	40	80	100	Y	-	9.6	70	-
Glenbrook	Cogen	Gas	GLN	50	112	80	100	Y	-	9.6	82	-
Whirinaki	OCGT	Diesel	WHI	25	155	85	33	N	10,906	11.6	23	-
Stratford	OCGT	Gas	SFD	42	210	85	50	N	8,907	9.4	19	0.44

Plant name	Plant Technology Type	Energy Type	Substation	Project Lifetime (Years)	Capacity (MW)	Availability Factor (AF) (%)	Unit Largest Proportion (ULP) (%)	Baseload (Y/N)	Heat Rate (HHV) (GJ/GWh)	Variable O&M (VOM) (2020 NZD $/MWh)	Fixed O&M (FOM) (2020 NZD $/kW/yr)	Fuel Delivery Costs (FDC) ($/GJ)
Edgecumbe	GT	Gas	EDG	37	10	80	100	N	11,500	4.9	35	-
Mangahewa	Recip	Gas	SFD	30	9	85	33	N	11,600	14.2	19	-
New Plant Since 2011 Report												
McKee	GT	Gas	MKT	37	100	85	50	N	-	9.4	19	-
Bream Bay	Recip	Diesel	BRB	25	9	85	20	N	-	14.2	19	-
Junction Road	GT	Gas	JKT	37	100	85	50	N	-	9.4	19	-

3.1.1.1 THERMAL GENERATION PLANT FLEET CHANGES OVER THE LAST 9 YEARS

Since the last report was completed in 2011, a number of thermal generation plants have now been retired from service. These include Southdown and Southdown E10, Otahuhu B and Huntly Unit 3. This reflects the changing NZ electricity market, fuel markets and the push for NZ to have more renewable energy supplied to the national grid. There have been a few new thermal plants commissioned during this period included within this report. These include Bream Bay Peaker, McKee and Junction Road, with the proposed Waikato Power Station a future build option for Todd Generation, near Otorohanga.

Table 3-4 Thermal Generation Organisations/Operators

Owner/Operator	Thermal Generation Plant
Genesis Energy	Huntly
Contact Energy	Stratford Taranaki Combined Cycle Te Rapa Whirinaki
Todd Generation Taranaki	McKee Junction Road WPP (proposed)
TrustPower	Bream Bay Peaker
BlueScope	Glenbrook
Fonterra/Nova Energy	Hawera (Whareroa Power)
Nova Energy	Edgecumbe Mangahewa Kapuni
Oji Fibre Solutions	Kinleith

The following table shows the generators who have been approved as a type A or type B industrial co-generating station under Schedule 13.4 of the Electricity Industry Participation Code 2010[2].

The two types of co-generators are described as:[3]

Type A co-generator: a co-generator that operates under the current offer, dispatch, and pricing rules.

Type B co-generator: a co-generator that will be treated in the same way as intermittent generators for dispatch and pricing purposes.

EA Register of generators approved as Industrial Co-generators:

Electricity Industry Participation Code 2010
Register of Generators approved as Industrial Co-generators

Updated: 14 February 2020

The Authority has approved the following generators as type A or type B industrial co-generators under Schedule 13.4 of the Code:

Number	Generator Name	Co-Generating Unit	Type A or type B	Date Approved	Duration of Approval	Conditions
1	Carter Holt Harvey Pulp and Paper Ltd	Kinleith Mill Turbine Generator	B	16 October 2015	Ongoing	▪ Grid Emergency. The co-generator must comply with dispatch instructions where the system operator has issued a formal notice as defined in Part 1 of the Code.
2	Alinta Energy (NZ) Ltd	Kilns Cogen Plant, Glenbrook Power Station	A	31 July 2007	Ongoing	▪ Grid Emergency. The co-generator must comply with dispatch instructions where the system operator has issued a formal notice as defined in part 1 of the Code.
3	Todd Energy Ltd and Whareroa Power Ltd Unincorporated Joint Venture	All 5 units at the Whareroa Co-generator	B	9 September 2019	Ongoing	▪ Compliance with Part 8: Continues to comply with voltage Part 8 Code obligations; and ▪ Load and generation agreements: Continues to adhere with load and generation agreements for system security during outages; and ▪ Grid Emergency: Complies with all dispatch instructions from the system operation under emergency conditions or to alleviate a system constraint
4	Norske Skog Tasman Ltd	All 4 units at the Kawerau site	A	14 October 2013	Ongoing	Norkse Skog Tasman must comply with dispatch instructions if: ▪ the system operator has issued a formal grid emergency or warning notice applicable to the area supplied by grid exit points in the Kawerau area; or ▪ a constraint situation, which is directly impacted by the Norske Skog industrial co-generating station, exists within the area supplied by grid exit points in the Kawerau area.
5	Kapuni Energy Joint Venture	All 4 generation units	A	2 March 2020	Ongoing	▪ Compliance with Code clause 13.86(c) ▪ Compliance with Part 8: Continues to comply with voltage Part 8 Code obligations; and ▪ Load and generation agreements: Continues to adhere with load and generation agreements for system security during outages; and ▪ Grid Emergency: Complies with all dispatch instructions from the system operation under emergency conditions or to alleviate a system constraint

There are currently three applications awaiting processing:

1. Whareroa Type B Cogeneration Application 2019
2. Kapuni Energy Type A Cogeneration Application 2019
3. Glenbrook Cogeneration Application 2020

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[2] https://www.ea.govt.nz/code-and-compliance/the-code/part-13-trading-arrangements/13-3-approval-process-for-industrial-co-generating-stations/

[3] https://gazette.govt.nz/notice/id/2015-au941

3.1.2 THERMAL PLANTS TECHNOLOGY OVERVIEW

3.1.2.1 BREAM BAY PEAKER

Trustpower owns and operates the Bream Bay Power Station near Whangarei, in Northland. Installed in 2011, the station is Trustpower's only thermal generation and is fuelled by diesel.

Bream Bay's diesel generators are located adjacent to Refining NZ's oil refinery at Marsden Point. There are five containerised XG2000 V16 Caterpillar engine/generator 1.8 MW units providing a combined output of 9 MW. Each of the generators has a 5,000-litre fuel tank and all are connected to a 30,000-litre bulk storage tank. Diesel fuel is delivered to the site by local fuel tanker trucks on a required basis. Each unit has its own transformer, outdoor control kiosk and standard 2 door cubicle.

The units are remotely operated via Trustpower's remote control centre in Durham Street, Tauranga. They are normally only put into service during trading periods when the prices are relatively high or favourable. This tends to be during periods of high electricity demand and in times of reduced power security

The Station is connected to the grid via Northpower's distribution network.

With intermittent service and regular maintenance, it is likely that these units have a remaining life of 30 to 40 years.

3.1.2.2 EDGECUMBE

The Edgecumbe cogeneration plant is owned and operated by Nova Energy, which is part of the Todd Corporation https://toddcorporation.com/

This cogeneration plant is used to provide power and energy requirements for Fonterra's Edgecumbe dairy processing factory. At times excess electricity is generated and is supplied to the local power grid.

This plant was established in 1996. The plant capacity is 10MW and is powered by two GEC Typhoon OCGT units, fuelled by natural gas. The power station is capable of also producing 60 tonnes of steam per hour for the onsite dairy processing plant.

3.1.2.3 GLENBROOK

The Glenbrook steel manufacturing mill is located south of Auckland and owned by BlueScope (which incorporates New Zealand Steel and Pacific Steel). The Glenbrook Power Station is a co-generation plant which is fully integrated into the steel mill to assist to optimise the mills energy costs.

The Glenbrook power and heat cogeneration system consists of two plants, the Multi Hearth Furnaces Cogeneration Plant (MHF Cogen) and the Kilns Cogeneration Plant (Kilns Cogen) with a total capacity of 112 MW. The MHF Cogen was commissioned in 1987, and the Kilns Cogen came online in 1997.

Glenbrook produces an average annual electricity output of 550 GWh. The combined output of the Kilns Cogen and the MHF Cogen plants meets on average around 60% of the electricity requirements for the mill – the shortfall is met by the grid.

Kilns Cogeneration Plant Description

The Kilns Cogen plant has 4 fired waste heat boilers which generate superheated steam at 65 bar(g) and 510˚C and feeding into a single 72MW rated steam turbine.

Kiln Off Gas (the waste gas generated by the Direct Reduction Kilns) is the primary fuel source for the Kiln Boilers. Supplementary fuels for the Kiln Boilers include Melter Gas (a by-product gas produced from the Melters) and Natural Gas.

The Kiln Boilers are each directly connected to a Direct Reduction Kiln. The Kiln Off-Gas (the primary fuel for the boilers) releases both chemical and heat energy as it is combusted in the Kiln Boilers. The boiler's operation is entirely dependent on the kiln operation – if the kiln stops, then so does the boiler. The Kiln Boilers also use the carbon monoxide rich Melter Gas as supplementary fuel. Natural Gas is used to start-up and shut down the Kiln Boilers safely, to provide boiler stability during low kiln feed rates when there is insufficient energy in the waste gases. Natural gas is used as a supplementary fuel.

The output of the Kilns Cogen generator is stepped up to 33kV via a generator transformer and is connected to the Glenbrook Substation via CB2462.

Whilst running 4 Kilns, the output from the Kilns Cogen is between 48 – 56 MW from a combination of the Melter and Kiln Off Gases. If a Kiln Boiler trips or NZ Steel shuts down a Kiln, the output of the Kilns Cogen can be instantaneously reduced by 25% or between 12 and 14 MW.

Cogeneration Plant integration with the steel mill

It is understood that the cogeneration plant is an embedded, bottoming cycle, cogeneration plant on the site of, and integrated with the steel plant. The cogeneration plant produces electricity as a by-product of steel production, as well as producing steam for the host's steel making processes.

NZ Steel's steel making process at Glenbrook produces high temperature combustible gases, which provide energy for the cogeneration plant, from two sources:

1. As an extension of the cogeneration development in 1997, a waste heat boiler (WHB) produces site process steam, utilising waste energy from the slab reheat furnace (SRF) at the Hot Rolling Mill.
2. The Glenbrook Power Station, comprising the MHF Cogeneration Plant and Kilns Cogeneration Plant is different from conventional power stations and cogeneration plants in the following ways:

- The inlet energy for the MHF cogeneration plant, except for times when surplus melter gas is used, is entirely sensible heat or thermal energy, with the inlet gases at up to 1,000˚C. (Combustible gases are fired in MHF afterburners prior to entering the MHF boilers. The MHF boilers are "unfired").
- The inlet energy for the Kilns cogeneration plant is a combination of thermal energy (gases between 800˚C and 1,200˚C) and chemical energy (combustible gases, with carbon monoxide being the major component).
- The SRF waste heat boiler is unfired, using the thermal energy (up to 600˚C) in the exhaust from the gas-fired slab reheat furnace.
- Part of the generated electricity (from the MHF cogen) is distributed to the steel plant directly by connections to its 11 kV system, with the bulk (from the Kilns cogen) connected by cable to the adjacent Transpower substation and the power thence distributed back into the steel plan system.
- Operation of the Glenbrook Power Station plant is totally dependent on operation of the steelworks.
- Under certain conditions of MHF and Kiln operation, there is opportunity for discretionary generation of up to approximately 14 MW by supplementary firing the Kilns Cogeneration Plant boilers with natural gas.

Apart from the opportunity for discretionary generation of up to approximately 14 MW, the Glenbrook plant has no flexibility in its ability to produce electricity and steam for processing heating in varying proportions.

The Kilns Cogen are currently approved by the EA to operates as a Type A Industrial Cogeneration Plant.

3.1.2.4 HAWERA (WHAREROA POWER)

The Whareroa Power Plant was originally an unincorporated joint venture originally between Whareroa Power Limited and Todd Energy Limited. It is now a joint venture between Fonterra and the Todd Corporation, with Nova Energy representing the Todd Corporation.

The Whareroa Power Plant is located onsite at Fonterra's factory in Hawera, Taranaki. The primary fuel supply is untreated Kapuni gas /distillate. Natural gas is used to drive four turbine generators equipped with a heat recovery boiler (HSRG), which captures the thermal energy from the turbine's exhaust and uses it to make steam. The Whareroa Power Plant's cogeneration system has a variable steam supply for its steam turbine; steam supply depends mainly on the residual quantity left after dairy factory steam demand. The plant provides the majority of steam and electricity for much of the Hawera dairy factory site.

The cogeneration plant configuration is:

- 4 x 10 MW gas turbines (Solar Turbines Ltd brand).
- 1 x 28 MW steam turbine.

The 5 units give the site a total generation capacity of 68MW.

The four gas turbines have waste heat boilers – Heat Recovery Steam Generators (HRSGs) attached to them for steam generation.

The Whareroa dairy factory site is made up of several independently operating dairy factories that take steam and electricity from the cogeneration plant. Fluctuations in factory electricity demand affect the net electricity available for export. Fluctuations in factory steam demand can affect steam turbine MW output.

The Whareroa Power Plant electricity production is a function of the following:

- Gas fired Turbine production.
- Steam turbine production which is dependent on steam available for production, and extraction steam load from the factory. Steam available for production is dependent on HRSG production and dairy factory demand for steam.
- Electricity load at the dairy factory site.

In addition, there are several parameters and constraints for the plant to operate within including:

- cooling capacity constraints.
- minimum running levels for the steam turbine.

The Whareroa power station is currently approved by the EA to operates as a Type B Industrial Cogeneration Plant.

3.1.2.5 HUNTLY UNITS 1, 2 & 4

The Genesis Energy, Huntly Rankine Units 1, 2 & 4 are standalone coal/gas fired thermal power units. The station has been New Zealand's largest thermal generation facility, with an original total generating capacity of 1,000 MW (now reduced to 750 MW).

There have been no similar thermal power plants constructed in NZ, which makes this plant unique in NZ, although many similar plants exist globally.

Originally this plant comprised of four 250 MW Parson turbines, commissioned between 1982 and 1985. Due to challenges in the electricity market for large thermal plant, Huntly Unit 3 was decommissioned in 2012. Since this time, Genesis has removed some of the remaining Rankine units from normal service and put them in storage for long periods. As pressure from the electricity market has increased, units have been made available for service.

In February 2018 the company announced it would end its use of coal for power generation by 2030. For this report WSP has focused on the remaining three Rankine units (1, 2 and 4) which as at the time of writing this report, Genesis is stating that they are likely to remain available for service using coal up until 2030, (natural gas fuelling could extend this duration). After this 2030 date, the repowering of the Rankine units is possible as Huntly is a strategically important generation location, close to the Auckland/Waikato load centres, has existing grid connections, existing natural gas pipeline infrastructure and site operating consents running through to 2036.

Table 3-5 Huntly Rankine Units Lifecycles

Identification	Capacity	Energy	Commissioned	Decommissioned
Unit 1 – HLY01	250 MW	Coal / Gas	1981	
Unit 2 – HLY02	250 MW	Coal / Gas	1983	
Unit 3 – HLY03			1984	2012
Unit 4 – HLY04	250 MW	Coal / Gas	1985	

Table 3-6 Huntly Rankine Units plant information

Units	Fuel Conversion	Turbine	Generator	Outputs
HLY01, HLY02 and HLY04	Coal and/or gas fuelled corner fired Combustion Engineering (CE) drum boiler (sub-critical) with superheat, reheat and economiser sections.	C E Parsons 16.3 mpa.abs 538˚C / 538˚C seven stage reheat cycle system. Single flow HP & IP cylinders and a double flow LP cylinder. Single pass condenser. Weir, main boiler feed pump unit.	C E Parsons liquid /hydrogen cooled type generator, coupled to direct driven main & pilot brush-less exciters. 2 pole rotor at a speed – 3000 RPM. Output 16.5 kV – 9,719 amps at nominal rating.	250MW / 277.8MVA nominal rating.

Operations

The Huntly Rankine units are identical 250 MW (gross), conventional, sub-critical[4], Rankine cycle, thermal generation units (boiler and steam turbine). The units' boilers are dual fuelled and designed to burn various combinations of natural gas and sub-bituminous coal. Heat rejection from the steam turbine condensers is to the Waikato River using once-through river water cooling. The boilers were designed from the outset to be dual fuelled with either coal and/or gas.

The Huntly Rankine units are powered using a combination of natural gas and/or imported (typically sourced from Indonesia) and locally sourced coal (typically locally sourced from nearby Rotowaro mines). In each of the units, coal/gas is burnt inside the boiler furnace, which generates steam at 540 degrees Celsius and 184 Bar or 2,700 PSI pressure. Once the energy from the steam has been extracted, it is re-condensed back into the boiler in a closed cycle. The boiler make-up water is produced onsite via a specialist water treatment plant, which also services Unit 5 (CCGT).

The steam turbine condensers use water from the Waikato River for cooling. The Huntly Power Station Resource Consent states that the maximum temperature of the river 1 km upstream of the Huntly Power Station cooling water outlet is to be 25 degrees Celsius (generally). This means that on low water flow, hot summer days, with the river water naturally heating up from the sun, generation from the Huntly Rankine units can be restricted or even stopped completely. This is mitigated by a cooling tower unit installed around 2010, which allows for one Rankine unit to operate up to a

[4] Sub-Critical Power Plant: A typical example of this system is the drum-type steam generator (boiler). Natural circulation is produced by heating of the risers. The water/steam mixture leaving the risers is separated into water & steam in the drum at the top of the boiler. The steam flows into the superheater and the water is returned to the evaporator inlet through down comers.

loading of around 150 MW, even during summer periods. During 2020, all three Rankine units have been in service in various capacities to support the security of supply.

This ongoing variability of the commercial availability of these thermal units is likely to continue through to 2030, depending on weather conditions, hydro lake storage and electricity market variability. Units are likely to be placed in various forms of storage if the demand forecast appears low for long periods of time. Ongoing O&M costs, including recertification costs, means it is expensive to keep these Rankine units available for service with low utilisation hours.

3.1.2.6 HUNTLY UNIT 6 (P40)

The Genesis Energy, Huntly Unit 6 (formerly known as P40 during construction) is a 48 MW open cycle gas turbine (OCGT). Unit 6 was commissioned in 2004.

Unit 6 is located on the Huntly Power Station site alongside the coal/gas fired Rankine thermal power station (Huntly Units 1, 2 & 4) and the combined cycle gas turbine (CCGT) power station (Huntly Unit 5).

Unit 6 consists of a General Electric (GE) LM6000 SprintTM aero derivative open cycle gas turbine, which drives a generator via a gearbox. This unit has dual fuel capability, either using natural gas, or converted over to use diesel fuel. The unit is normal rated at 48MW but is capable of producing an output of 50.8MW.

Table 3-7 Huntly Unit 6 plant information

Unit	Fuel Conversion	Turbine	Generator	Transformer	Output
Huntly Unit 6 HLY06	Natural Gas and Fuel Oil (Diesel Distillate)	General Electric (GE) LM6000 gas turbine engine.	Brush (FKI) 50Hz air-cooled AC Generator. Output – 11kV 3,000 RMP	ABB 11/220kV step-up generator transformer rated at 42 MVA, ONAN cooling. 50Hz, 3 phase power transformer	48 MW

3.1.2.7 HUNTLY UNIT 5 (E3P)

The Genesis Energy, Huntly Unit 5 (formerly known as E3P during construction) uses natural gas to generate up to 403 MW of electricity, depending on ambient air temperatures (normal capacity rated at 385 MW). Unit 5 was commissioned in 2007.

Huntly Unit 5 consists of a 250 MW gas turbine (GT), heat-recovery steam generator (HRSG) and a 135 MW steam turbine, which together provide a normal output of 385MW. Unit 5 is able to generate up to 403MW in cooler weather conditions. Cooling is provided by a standalone cooling tower which doesn't utilise Waikato River water.

Huntly Unit 5 is located at Huntly in the Waikato, alongside Genesis' coal/gas fired Rankine thermal power station (Huntly Units 1, 2 and 4) and open cycle gas turbine (Huntly Unit 6).

Genesis have said that electricity generation can be expected to continue at the Huntly site for many years to come from the two-existing gas-fuelled units, including Huntly Unit 5. The company have also indicated that the site remains extremely well positioned to develop additional thermal peaking capacity, should that be required in the future.

The Huntly Power Station site was re-consented in May 2012. The new consents allow for the thermal generation operations on the site until 2038.

Huntly Unit 5 is a high-efficiency combined cycle generator consisting of four major components:

1. 250MW industrial gas turbine made by Mitsubishi Heavy Industries (Mitsubishi 701F3 gas turbine)
2. HRSG
3. 135MW steam turbine
4. a wet-dry (hybrid) type cooling tower equipped with plume abatement.

Huntly Power Station is located close to major population centres, has reliable access to cooling water, coal and gas resources, and benefits from limited transmission constraints. This, together with long-term resource consents, means that the Huntly Power Station is expected to continue to provide Genesis Energy with both a valuable asset and a range of future development options.

The Huntly Power Station has the ability to provide base-load generation while also being able to take advantage of higher prices in the short or medium term. In recent times Unit 5 has operated in a 2-shifting operational mode (meaning the unit may ramp up output in the morning peak electricity demand period, reduce output and then ramp up output during the peak evening demand period, before reducing output overnight to meet electricity market demands). Up until this time, Unit 5 was operated more in a base load mode. The plant is designed for a 2-shifting operational mode, but there are increased maintenance costs over time due to more starts and stops with 2-shifting operation compared to base load operation.

The mix of generating units at the Huntly site is likely to change over time as the older Rankine gas/coal-fired generation units are placed into various forms of storage, retired or replaced. The Huntly unit 3 Rankine unit has already been retired.

3.1.2.8 JUNCTION ROAD

The Junction Road Power Station is a newly constructed, $100 million natural gas-fired peaker power plant which begun production in in May 2020 in Taranaki.

Todd Generation Taranaki Limited's (Todd Generation) 100 MW Junction Road power plant is located 7km south of New Plymouth. The plant is fuelled from the First Gas natural gas pipeline and connected to the national electricity grid. Todd Generation Taranaki Ltd. is part of the Todd Corporation.

The plant is a similar configuration to the nearby McKee Power Station, in that it incorporates two 50 MW GE LM6000 Open Cycle Gas Turbines (OCGT). The Junction Road plant has some of the latest GE LM6000 plant developments, including the Sprint options for improved performance. Both of these GT power stations are now capable of being both locally controlled, or remotely controlled by a Todd Generation remote control centre in the New Plymouth CBD. The future WPP (Waikato Power Plant) near Otorohanga is also expected to be remotely controlled from this facility.

3.1.2.9 KAPUNI

Nova Energy's cogeneration plant at Kapuni, in Taranaki, has a capacity of 25MW.

The cogeneration plant is now wholly owned by Nova Energy, part of the Todd Corporation.[5]

The Kapuni co-generation plant is located at Todd Energy's Kapuni Gas Treatment Plant (KGTP) (which was Todd purchased from Vector in 2019). This cogeneration plant supplies both steam and electricity to the KGTP and a local dairy processing plant. Excess electricity generated is exported via Nova Energy to the grid.

The Kapuni co-generation plant consist of four generation units:

- Two 10.5 MW Solar Mars gas turbines and associated heat recovery steam generators located at KGTP.
- One 1.5MW back-pressure steam turbine at KGTP,
- One 2MW steam turbine located at the dairy site.

Kapuni is currently approved by the EA to operate as a Type A Industrial Cogeneration Plant

3.1.2.10 KINLEITH

The Kinleith cogeneration plant is an important part of the Kinleith pulp and paper mill, which is New Zealand's largest mill of this type.

Located near Tokoroa in the Central North Island, Kinleith is owned by Oji Fibre Solutions.

The Kinleith cogeneration plant was established in 1998 and has an overall capacity of 40 MW.

On site electricity is produced from steam from two recovery boilers burning black liquor (a concentrated mix of spent chemicals and lignin dissolved out of the wood in the kraft pulping process) and from a power boiler firing wood waste, cofired with gas to manage swings in steam demand.

The wood waste used to fuel the power boiler is supplied from both on-site processing and trucked in from forest operations and outlying sawmills around the central North Island. The turbine

[5] Previously the Kapuni Energy Joint Venture (KEJV) which was an unincorporated joint venture between Vector Kapuni Limited (Vector) and Nova Energy Limited (Nova) owned this plant.

exhaust steam is used in the mill's pulping and drying processes. This utilisation of the process steam from the onsite cogeneration power plants adds significant value to the effective operation of the mill. In the future it is planned that the cogeneration power facilities will expand as the mill expands to match the expected growth in the availability of local forestry stock in the next 10 years.

Currently 32 to 35MW's of electricity is base load generated to contribute to the mill's normal demand load of around 65 to 70MW's. Additional mill power demand is supplied via the adjacent Kinleith Substation.

As this co-generation electricity is generated as a result of the steam required by the production plant for mill operations, using predominately biofuel, this electricity generation is a by-product with minimal cost to the site.

Kinleith is currently approved by the EA to operate as a Type B Industrial Cogeneration Plant.

Table 3-8 Kinleith Cogeneration Plant Information

Unit	Fuel Conversion	Turbine	Generator	Transformer	Output
Cogeneration Plant	The wood-waste and gas fired power boiler (NO.8) acts as a swing boiler with the existing No.4 & 5 recovery boilers, which integrate into the P & P Mill co-generation plant & provide steam to the SRG.	Allen 39.6 Mwe Type H-6, pass-out back pressure steam turbine (STG) driving a Peebles generator through an Allen Gears parallel shaft speed reduction gearbox. Gear speed – 4393/1500 rpm.	Peebles Electrical Machines – Output: 40MW 46.5MVA 11kV 2445 Amps 1500 rev/min 4 pole Brush-less excitation	Nil Direct feed to internal Kinleith Mill substation	40MW Process steam for Paper Mill demands.

3.1.2.11 MANGAHEWA

The 9 MW Mangahewa power station is owned by Nova Energy (part of the Todd Group). It is located at the Mangahewa oil and gas field, in Taranaki. The plant was established in 2009 and has a mean annual average output of 23 GWh.

The Mangahewa power station consist of three 3 MW GE Jenbacher internal combustion turbines. This plant is fuelled using raw well head gas from the Mangahewa - 3 oil and gas production well (as opposed to using the traditional pipeline refined natural gas). Electricity generated is supplied to the local network.

3.1.2.12 MCKEE

The McKee peaking plant is owned by Todd Generation Taranaki Limited (part of the Todd Corporation). Todd began construction in 2011 and commissioned the 100 MW power station in late 2012.

McKee is located near the Todd Energy McKee-Mangahewa production facility near Waitara, Taranaki.

The McKee power plant consists of two 50 MW GE LM6000 Open Cycle Gas Turbines (OCGT), fuelled by natural gas supplied from the adjacent McKee and Mangahewa gas fields.

The plant is designed as a peaking power plant with a 15-minute, cold start to full load operation capability, although for much of its life to date it has operated for long period of base load as well. This plant is now capable of being remotely operated via Todd Generations new remote-control centre in New Plymouth CBD.

3.1.2.13 STRATFORD

Contact Energy's 210 MW natural gas-fired Stratford peaker power station in Taranaki and commissioned in early 2011.

The Stratford peakers two units are high efficiency General Electric LMS-100 gas turbine generators.

The gas turbine peaking units have been installed on the site of Contact's former Stratford power station, adjacent to the company's existing Taranaki Combined Cycle (TCC) power station, which has been operating at the site since 1998. Together, TCC and the two new peakers produce a total combined site output of 587MW.

The LMS-100 is a fast start, high efficiency gas turbine developed especially for electricity generation. It brings together a heavy-duty frame compressor and aeroderivative gas turbine technology, with an intercooler and power turbine.

The Stratford peakers are able to utilise stored natural gas from the nearby Ahuroa Gas Storage Facility.

3.1.2.14 TARANAKI COMBINED CYCLE (TCC)

The 377 MW Taranaki Combined Cycle (TCC) Power Station was commissioned in 1998. Owned and operated by Contact Energy, this plant is located alongside Contact's open-cycle gas peaking plant in Stratford, Taranaki.

The plant is a natural gas fuelled, 377 MW capacity (357 MW at commissioning), single shaft, combined cycle gas turbine plant (CCGT) using the Alstom GT26 gas turbine. The steam turbine condenser is cooled by a wet-dry (hybrid) type cooling tower equipped with plume abatement capability.

TCC is able to utilise stored natural gas from the nearby Ahuroa Gas Storage Facility.

3.1.2.15 TE RAPA

Contact Energy's Te Rapa cogeneration power station is a relatively small gas-fired power station generating 44 MW of electricity. The Plant was commissioned in 1999. Te Rapa was built primarily to provide a secure supply of electricity to Fonterra's neighbouring Te Rapa milk processing factory in the Waikato.

The Te Rapa power station is a cogeneration plant, meaning that it uses natural gas to produce two different forms of energy – electricity to power the Fonterra factory, as well as steam for direct use within the factory.

In a combined cycle gas plant, the steam would be used to generate more electricity rather than as a source of energy for direct use. At maximum output, the Te Rapa power station can provide the Fonterra factory with 180 tonnes of steam per hour.

Te Rapa normally runs in cogeneration mode, providing roughly 15 MW of electricity and steam to the Fonterra factory and 30MW of electricity back into the local electricity distribution network.

- Generation capacity: 44 MW
- Gas turbine: General Electric Frame 6B

- Maximum steam output: 180 tonnes per hour
- Te Rapa normally runs in cogeneration mode, providing roughly 15MW of electricity and steam to the Fonterra factory and 30MW of electricity back into the local electricity distribution network.
- The plant is fitted with a GT exhaust bypass, enabling the GT to operate as an electricity generator only, without producing steam

The plant is based on a gas turbine (a GE frame 6B) which can produce up to 44 MW of electricity. Hot exhaust gases from this gas turbine are ducted to a HRSG to raise steam. This HRSG has duct burners to increase steam output, which can be up to 180 tons of steam per hour. The plant is fitted with a GT exhaust bypass, enabling the GT to operate as an electricity generator only, without producing steam.

The 44 MW cogeneration plant is designed for flexible operation, and can provide electricity to the dairy factory, export electricity to the local network or import electricity for use in the dairy factory. A common operating mode is 30 MW of electricity exported and 14 MW plus 120 tons per hour of steam provided to the dairy factory.

3.1.2.16 WHIRINAKI

The Whirinaki peaker plant is a 155MW, diesel fired peaker plant located at Whirinaki in Hawkes Bay. This plant is owned and operated by Contact Energy. The plant was established in 2004. As the plant is fuelled by diesel, it is predominantly used to cover power supplies during adverse electricity market conditions such as dry years or natural gas supply shortages.

Whirinaki plant is a 155 MW, diesel fuelled, open cycle gas turbine power station using three Pratt & Whitney FT8 Twin Pac gas turbine generators. The FT8 gas turbine is an aero-derivative gas turbine derived from the Pratt & Whitney JT8D turbofan aircraft engine. In the TwinPac configuration, two FT8 aero-derivative gas turbines, each rated at around 26 MW are directly connected to each end of a centrally located Brush generator.

It is possible to operate this generator unit using only one power turbine end at a time, but the power turbine of the non-operating end turns as there is no clutch between the power turbines and the generator, which makes this operational mode a lot less efficient. Normally, however, both power turbine ends are used to meet a dispatch signal and the load is shared between each gas turbine engine.

The gas turbines need water injection to control exhaust emissions to meet consent requirements. Three on-site staff manage the plant, which can also be operated remotely from Contact's Te Rapa Power Station.

Approximately 92 hours of full load generation is possible, utilising the approximate 4 million litres of diesel fuel stored on site.

To run this plant for more than the above duration, additional diesel fuel is required which needs to be transported to the site via road tanker units.

Whirinaki power station

3.1.3 ENERGY TYPE

This section records the type of fuel used at each thermal plant and in some cases explains how this fuel is resourced.

3.1.3.1 BREAM BAY PEAKER

The Bream Bay Peaker plant is fuelled by diesel.

3.1.3.2 EDGECUMBE

The Edgecumbe cogeneration plant is fuelled by natural gas.

3.1.3.3 GLENBROOK

The Glenbrook cogeneration plant is fuelled by coal, natural gas and utilities waste heat from the steel production plant.

Kilns Cogen

The Kilns Cogen consists of 4 fired waste heat boilers generating superheated steam at 65 bar(g) and 510 degrees C to feed a single steam turbine rated at 72 MW.

The fuel source for the Kiln Boilers is primarily Kiln Off Gas, the waste gas generated by the Direct Reduction Kilns. Supplementary fuels for the Kiln Boilers include Melter Gas, a by-product gas produced from the Melters and Natural Gas.

- In addition to natural gas being used for starting and shutting down boilers safely, it can be used as a supplementary fuel.
- Natural Gas used as a supplementary fuel can contribute an additional 10-12 MW.
- Provide stabilisation fuel during periods where there is insufficient chemical and sensible energy in the Kiln Off Gases

MHF Cogen

Ironsand and coal are fed into 4 Multi Hearth Furnaces (MHF) where the coal and ironsand are heated to produce char and primary concentrate. The waste heat from this process, feeds the MHF Cogen plant.

The mills objective is to maximise the generation of electricity from the available waste energy and the by-product gases – any electricity not generated from the available fuels is seen as a lost opportunity as this electricity is replaced by electricity supplied from the grid.

3.1.3.4 HAWERA (WHAREROA POWER)

The Whareroa cogeneration plant is fuelled by natural gas.

3.1.3.5 HUNTLY UNITS 1, 2 & 4

The Huntly Rankine units (Units 1, 2 & 4) are able to be fuelled with a combination of coal and natural gas. The units require a fuel oil supply to be used to initially fire the boilers and then natural gas is used to bring the boiler pressures up. Once the unit is at a high range, pulverised fuel (black coal) mixed with hot air is introduced to the boiler fire ball and then the natural gas can be backed off to suit the required loading of each unit.

Coal supplies and stockpiles

Genesis has extensive coal stockpiling infrastructure onsite and close to the 5 km coal conveyor loading point at the old Huntly West coal mine site, as well as the covered storage facility at the Port of Tauranga where imported coal is held before being transported to Huntly to supplement local supply. Coal ash management is an ongoing challenge at Huntly. The ash content of supplied coal is an important factor which is taken into consideration due to the amount of effort required to manage the residual ash once it exits the boiler ash hoppers.

Natural gas supplies

Genesis has some security of gas supply via their 46% interest in the Kupe Joint Venture, which owns the Kupe oil and gas field in Taranaki. This natural gas supply still relies on the single Maui pipeline to deliver natural gas to the Huntly Power Station site.

Due to reductions in natural gas availability, the Huntly Rankine units have continued at times to use coal to meet generation demands. Natural gas supply constraints have been caused by events such as planned and unplanned gas production facility outages, gas pipeline infrastructure issues and supply constraints due to other pipeline users in Auckland and Northland.

3.1.3.6 HUNTLY UNIT 6

Huntly Unit 6 is dual fuelled with natural gas or diesel. A charge over process is required to swop fuels. A moderate diesel supply is maintained within onsite storage takes. Natural Gas is predominantly used and is supplied by the same supply source as Huntly Unit 5.

3.1.3.7 HUNTLY UNIT 5

Huntly Unit 5 CCGT is fuelled by natural gas via its own onsite gas compressors to maintain steady gas pressure to the GT. Natural gas is supplied via the Maui Pipeline via the First Gas Rotowaro Compressor Station.

3.1.3.8 JUNCTION ROAD

The Junction Road GT plant is fuelled by natural gas.

3.1.3.9 KAPUNI

Kapuni is fuelled by natural gas.

3.1.3.10 KINLEITH

This 41 MW noncondensing turbine and generator, generally runs to meet steam demand at 45 bar g, runs through the steam turbine. Some medium pressure take-off steam goes to the kraft process to separate lignin from the process wood. This sometimes need additional auxiliary steam, which can be supplied from a separate gas fired boiler and a wood waste / gas fired boiler, the number 8 primary boiler can also be used.

The Kinleith steam turbine generator, is effectively fuelled by one or more of black liquor, wood waste and natural gas. The primary fuels are black liquor[6] (two of three boilers only) and pinus radiata wood waste (one boiler only), including bark, chip fines and some sawdust. The secondary fuel for wood waste boiler only is natural gas.

Based on boiler capacity, black liquor could provide 79% of the steam required by the steam turbine generator, with the balance made up by wood waste and natural gas. The actual proportions of the various fuels used are not known.

Black liquor and wood waste are by-product waste streams from the pulp and paper mill process and are therefore zero cost fuels.

3.1.3.11 MANGAHEWA

Mangahewa is fuelled by Todd Energy's raw wellstream gas rather than the normal pipeline gas.

3.1.3.12 MCKEE

The McKee GT plant is fuel by natural gas.

3.1.3.13 STRATFORD

Stratford is fuelled by pipeline natural gas and can also use gas from the nearby Ahuroa underground gas storage facility.

The Firstgas Ahuroa underground storage facility has recently completed an upgrade and is now able to increase daily gas injection and gas extraction rates to 65 TJ per day.

3.1.3.14 TARANAKI COMBINED CYCLE (TCC)

The TCC CCGT plant is fuel by natural gas and can also use gas from the nearby Ahuroa underground gas storage facility.

3.1.3.15 TE RAPA

Te Rapa is fuelled by natural gas.

3.1.3.16 WHIRINAKI

Fuel is supplied to the gas turbines from two 2.2 million litre tanks which are located on the site. Fuel type is automotive diesel.

[6] 'Black liquor' is the spent cooking liquor from the Kraft pulp production process when digesting pulpwood into paper pulp by removing lignin, hemicelluloses and other extractives from the wood to free the cellulose fibres.

3.1.4 SUBSTATION

3.1.4.1 THERMAL GENERATION PLANT LOCATIONS

Currently all NZ Thermal Generation plants are located in the North Island, as shown in Transpower's North Island – Transmission Network Map. More detail is available by viewing the map on the following link: https://www.transpower.co.nz/sites/default/files/plain-page/attachments/Transmission-map-north-island0720.pdf

Table 3-9 Plant Substation ID's

Plant name	Plant Technology Type	Energy Type	Substation ID
Taranaki CC	CCGT	Gas	SFD
Huntly unit 5 (e3p)	CCGT	Gas	HLY
Huntly gas units 1,2 & 4	ST	Gas	HLY
Huntly unit 6 (P40)	OCGT	Gas/diesel	HLY
Huntly coal units 1, 2 & 4	ST	Coal	HLY
Kapuni	Cogen	Gas	KPA
Hawera (Whareroa)	Cogen	Gas	HWA
Te Rapa	GT	Gas	TRC
Kinleith	Cogen	Various	KIN
Glenbrook	Cogen	Gas	GLN
Whirinaki	OCGT	Diesel	WHI
Stratford	OCGT	Gas	SFD
Edgecumbe	GT	Gas	EDG
Mangahewa	Recip	Gas	SFD
McKee	GT	Gas	MKT
Bream Bay	Recip	Diesel	BRB
Junction Road	GT	Gas	JKT

3.1.5 PROJECT LIFETIME

These sections seek to determine how long each thermal generation plant can be reasonably expected to remain operational after commissioning. This subject was addressed in WSP / PB's previous report, "Thermal Power Station Advice, Report for the Electricity Commission", July 2009. That report noted that:

- Thermal power plant equipment design life is typically specified as 25 years operational life and 200,000 hours. A number of hot, warm and cold starts will also be specified. An equivalent operating hours (EOH) penalty will be associated with each start, stop or trip event.
- Thermal OCGT power plant used predominantly for peaking will be subjected to more starts (hot, warm and cold starts), so will incur reduced lifecycle before major refurbishment work is planned and implemented. This will increase the O&M costs for these units. These costs will look to be recovered via the high offer price received for suppling generation during peak load demand trading periods.
- Thermal power plant operating life can be, and often is maintained well beyond the original design life with the replacement and refurbishment of equipment.
- Worldwide it is observed that some coal fuelled steam and natural gas turbines are 40-50 years old and still in operation 20 years beyond the original nominal calendar design life.
- Whether thermal plants are refurbished, placed on standby or decommissioned before or at their design life remains primarily an economic decision for the owner. The economics of a unit are a function of market competitiveness, relating to potential net revenues versus the net costs which costs will include fuel, maintenance and capital costs. This decision is often difficult to make, and the outcome is often based on reasons which are not always transparent to uninformed outside observation.
- Observed plant retirement decisions in US and Europe have generally been made to replace still operable but older less efficient plant which require significant capital expenditure for emissions related upgrades required for regulatory compliance with newer more efficient (heat rate <7000 kJ/kWh) and lower emissions units.

That report estimated decommissioning dates for each of the NZ thermal plant included in the scope of the study. The estimation of these dates was based on a set of assumptions around the original design life and operating regime of the plant.

The updated information below has been sourced from the previous report, discussions with plant owners or WSP in-house information.

Table 3-10 Projected decommissioning dates of NZ thermal generation plant

Plant	Commissioning date	Design life (Years)	Original/ Projected decomm. date	Refurb. date	Refurb. Capex ($/kW)	Projected decomm. date with mid-life refurb.
Bream Bay Peaker	2011	25	2036	n/a	n/a	n/a
Edgecumbe	1996	25	2021	2008	n/a	2033
Glenbrook	1997	50	2047	n/a	n/a	n/a
Hawera (Whareroa Power)	1996	25	2021	n/a	n/a	n/a
Huntly PS - (Units 1,2 & 4)	1982 - 1985	25	2020	2020	864	2035
Huntly PS – U5 CCGT	2007	25 to 30	2037	2027	492	2057
Huntly PS – U6 OCGT	2004	25	2029	2021	400	2046
Junction Road	2020	25	2045	n/a	n/a	n/a
Kapuni	1998	25	2023	n/a	n/a	n/a
Kinleith	1998	50	2048	n/a	n/a	n/a
Mangahewa	2008	20 to 30	2038	n/a	n/a	n/a
McKee	2013	25	2038	n/a	n/a	n/a
Stratford	2011	25	2035	2028	n/a	2053
TCC	1998	25 to 30	2028	Est. 2023	.80	2048
Te Rapa	1999	25	2024	n/a	n/a	n/a
Whirinaki	2004	25	2029	n/a	n/a	n/a

3.1.5.1 BREAM BAY PEAKER

The Project Lifetime of the Bream bay Peaker plant is estimated at 25 years, based on discussions with the plant owner.

3.1.5.2 EDGECUMBE

The Project Lifetime of Edgecumbe, a gas turbine-based cogeneration plant is considered to be 37 years.

Without mid-life refurbishment plant of this nature should be able to operate to the original design life of 25 years of operation with regular maintenance. Given the plant was commissioned in 1996, and assuming the mid-life refurbishment of the unit occurred around 2008 this would extend the life of the plant out to 2033.

The Project Lifetime is therefore 37 years.

3.1.5.3 GLENBROOK

The Project Lifetime of Glenbrook, a boiler and steam turbine-based cogeneration plant is similarly considered to be 50 years.

3.1.5.4 HAWERA (WHAREROA POWER)

The Project Lifetime of Hawera is similarly considered to be 42 years.

3.1.5.5 HUNTLY UNITS 1, 2 & 4

Given that the main boiler plant was then approximately 25 years old and had consumed approximately 75% of the design operating hours, a prediction of a further 10 years of reliable operation to 2020 was reasonable based on the assumption that regular scheduled maintenance is performed without the need for mid-life refurbishment. This was supported by the fact that gas was the predominant fuel up to 2002, resulting in less wear and tear on the main coal and ash handling plant.

Extension of the life of the units beyond 2020's will be likely to require a significant refurbishment work. Given the nature of the plant and observed lives of similar plant around the globe, as long as the economics allow refurbishments to be executed, there should be no technical reason why the plant could not continue to operate for another 25 years, doubling the original design life to 50 years, with a projected decommissioning date of 2035.

The Project Lifetime is therefore 50 years.

Genesis has indicated that the intend to end the coal fuelling of the Huntly Rankine units by 2030. Gas may still continue to be a fuel option for these units.

The statutory recertification of these units is a key maintenance requirement which is now less straight forward due to the less consistent service levels for the units due to variable market conditions (mostly dry year cover). Previously these units have required an annual short recertification outage (Hot Survey – 2 - 4 weeks duration) and a 4 yearly (Cold Survey – 3 - 4 months during the summer periods when river heating restrictions occur). Genesis is likely to be looking at options to be approved to move to a Risk Based Inspection (RBI) methodology for these units based on the fuel used and the hours in service.

3.1.5.6 HUNTLY UNIT 6

Without mid-life refurbishment plant of this nature should be able to operate to the original design life of 25 years of operation with regular maintenance. Given the plant was commissioned in 2004, mid-life refurbishment of the unit would occur around 2021 and be likely to extend the life of the plant out to 2046.

The Project Lifetime is therefore 42 years.

3.1.5.7 HUNTLY UNIT 5

Without mid-life refurbishment, plant of this nature should be able to operate beyond the original design life to at least 30 years of operation to 2037. Mid-life refurbishment of the unit would occur around 2027 and be likely to extend the potential operating life of the plant out to 2057.

Given that this plant was commissioned in 2007, the Project Lifetime is therefore 50 years.

3.1.5.8 JUNCTION ROAD

Without mid-life refurbishment plant of this nature should be able to operate to the original design life of 25 years of operation with regular maintenance. Given the plant was commissioned in 2020, mid-life refurbishment of the unit would occur around 2032 and be likely to extend the life of the plant out to 2057.

The Project Lifetime is therefore 37 years.

3.1.5.9 KAPUNI

The life of the cogeneration plants has not previously been estimated by WSP. If the same principles applying to the other thermal power generators also apply to the cogeneration plants, then the same Project Lifetimes can be expected.

It is noted that cogeneration plants are generally dependent upon their process heating ‘hosts’. As long as the electricity price covers the cost of the fuel attributable to power, it seems likely therefore that the cogeneration plants will continue in operation as long as their hosts. The future life of the cogeneration hosts is indeterminate.

The Project Lifetime of Kapuni, a gas turbine-based cogeneration plant is therefore considered to be 42 years.

3.1.5.10 KINLEITH

The Project Lifetime of Kinleith, a boiler and steam turbine-based cogeneration plant is similarly considered to be 50 years.

Expected remaining life of the current plant is at least 10 years.

Future proposed Kinleith pulp and paper mill site expansions/upgrades are likely to include a substantial additional biofueled energy island co-generation plant with an anticipated output of around 100MW.

Future generation expansion options

Recently Oji have begun looking at a future upgrade and potentially a doubling of Kinleith throughput from 6,000-ton of kraft p.a. to over 1000,000-ton p.a. This is just one option being considered and would be in the 10-year timeframe, and a cost ballpark of $600 – 700m. Site energy costs are increasing over recent years. This has led Oji to look at putting in new high energy recovery boilers to better use the black liquor, with up 115 bar / 500°C. This would allow around a tripling of energy output from the same amount of black liquor.

This type of upgrade could be 3 to 10 years away, depending on if the major mill upgrade goes ahead.

If Oji were to just put in a new energy island (on-site energy production facility), it is likely to produce an additional 100MW of electricity, so would provide an excess of 35MW for export off site. The next option is to upgrade the whole plant, which would then require addition electricity importing from the grid.

3.1.5.11 MANGAHEWA

Mangahewa uses internal combustion (IC) or reciprocating engines. WSP has previously advised the Electricity Commission, in WSP report, "Thermal Power Station Advice – Reciprocating Engines Study", November 2009 that, "with proper maintenance, large engines have an operating life of 20 – 30 years".

The Project Lifetime of Mangahewa is therefore estimated at 30 years.

3.1.5.12 MCKEE

Without mid-life refurbishment plant of this nature should be able to operate to the original design life of 25 years of operation with regular maintenance. Given the plant was commissioned in 2013, mid-life refurbishment of the unit would occur around 2025 and be likely to extend the life of the plant out to 2050.

The Project Lifetime is therefore 37 years.

3.1.5.13 STRATFORD

Without mid-life refurbishment, plant of this nature should be able to operate to the original design life of 25 years of operation with regular maintenance. Given the plant was commissioned in 2011, mid-life refurbishment of the unit would occur around 2028 and be likely to extend the life of the plant out to 2053.

The Project Lifetime of Stratford is therefore 42 years as confirmed by Contact Energy.

3.1.5.14 TARANAKI COMBINED CYCLE

Without mid-life refurbishment, plant of this nature should be able to operate beyond the original 25-year design life to at least 30 years of operation taking decommissioning to around 2028. Mid-life refurbishment of the unit are expected to occur around 2023 and be likely to extend the life of the plant out to 2048. These refurbishments are generally publicised in advance in the media once planning decisions are confirmed.

Given that this plant was commissioned in 1998, the Project Lifetime is therefore 50 years as confirmed by Contact Energy.

3.1.5.15 TE RAPA

The Project Lifetime of Te Rapa is similarly considered to be 42 years, as confirmed by Contact Energy.

Contact's agreement with Fonterra for this plant expires in June 2023, so the long-term status of this plant has some uncertainty.

3.1.5.16 WHIRINAKI

Without mid-life refurbishment plant of this nature should be able to operate to the original design life of 25 years of operation with regular maintenance. This suggests a decommissioning date of 2029.

Given that this plant was commissioned in 2004, the Project Lifetime is therefore 25 years as confirmed by Contact Energy.

3.1.6 OPERATIONAL CAPACITY

These sections seek to determine the long-term operational capacity of the thermal generation plants.

It is understood that the GEM uses what is otherwise referred to in the industry as "net capacity" as opposed to gross capacity. The difference between net and gross capacity is the auxiliary power demand, or 'house load' or 'parasitic load' and is the power consumed by the plant internally.

Such power is used to drive fuel delivery and preparation equipment (conveyors, crushers, feeders and pulverising mills for coal fired plant, and gas compressors for gas fired plant if required), and process equipment such as pumps and fans. It also includes power and lighting requirements, and electrical losses in transformers.

3.1.6.1 BREAM BAY PEAKER

The net capacity of the Bream Bay Peaker plant is estimated as 9 MW

3.1.6.2 EDGECUMBE

The net capacity of the Edgecumbe plant is estimated as 10 MW

3.1.6.3 GLENBROOK

The net capacity of the Glenbrook plant is estimated as 112 MW

3.1.6.4 HAWERA (WHAREROA POWER)

The net capacity of the Kapuni plant is estimated as 68 MW.

3.1.6.5 HUNTLY RANKINE UNITS 1, 2 & 4

Huntly Gas

The Huntly units 1, 2 & 4, firing natural gas, WSP estimates this to be 245 MW per unit. This is consistent with WSP understanding for a unit with a gross capacity of 250 MW and around 2% auxiliary power demand.

Huntly Coal

The Huntly units 1, 2 and 4, firing coal, WSP estimates this to be 237 MW per unit on the basis of a gross capacity of 250 MW per unit and around 5% auxiliary power demand when firing coal.

As the Huntly Rankine units use a combination of both gas and coal, the units auxiliary power demand will vary from around 2% to 5%.

Resource consents

In May 2012, 25-year resource consents were granted for the generation capacity at Huntly which secure the site's future as a long-term generation site of national significance. This reflects its critical role in supplying electricity and important ancillary services such as frequency and voltage support.

Reporting

Compliance monitoring reports are produced in relation to a number of activities that are carried out at the Huntly Power Station. Some of the monitoring programmes are related to the resource consents and others are in response to community feedback. Genesis currently undertakes monitoring of:

- Air quality.
- Terrestrial and aquatic vegetation.
- Groundwater quality.
- Dust.
- Treated process water discharges.
- Stormwater.
- Temperature of cooling water discharged to the Waikato River.
- River ecology including fish.
- Integrity of structure located within the Waikato River.

A significant proportion of the environmental compliance monitoring required to be undertaken by Genesis at Huntly is related to the operation Huntly Rankine units. At different times of the year, particularly during the hot summer months, the Huntly Rankine units’ output is restricted to ensure consent compliance levels are not exceeded (e.g. Waikato River water temperature monitoring) This effectively controls the generation output of some of these units based on the river water mixing rate able to be achieved and monitored 1km downstream from the hot water outlet.

3.1.6.6 HUNTLY UNIT 6

Genesis Energy has declared the long-term operational net capacity of Huntly Unit 6 (P40) to be 40 - 48 MW. WSP recommends that the median value is assumed for the GEM, 44 MW. This is consistent with public domain data.

3.1.6.7 HUNTLY UNIT 5

The long-term operational net capacity of Huntly Unit 5 (e3p) is declared to be 385 MW. This is consistent with public domain data.

As with all GT power plants in NZ, the ambient air temperature will determine what level of generation output is able to be achieve during any given period.

3.1.6.8 JUNCTION ROAD

The net capacity of the Junction Road plant is estimated as 100 MW

3.1.6.9 KAPUNI

The net capacity of the Kapuni plant is estimated as 25 MW.

3.1.6.10 KINLEITH

Oji Fibre Solutions Kinleith co-generation plant has a capacity of 41MW. Typical generation is 32-35MW, with a mill site load is 65 to 70MW.

Oji Fibre Solutions currently have plans to upgrade to a plant capable of 100MW, producing roughly 850 gigawatt hours per annum.

Oji Fibre Solutions has not declared the long-term operational net capacity of Kinleith cogeneration plant. WSP previously estimated this to be 38 MW on the basis of a gross capacity of 40 MW and around 5% auxiliary power demand.

3.1.6.11 MANGAHEWA

The net capacity of the Mangahewa plant is estimated as 9 MW.

3.1.6.12 MCKEE

The net capacity of the McKee plant is estimated as 100 MW.

3.1.6.13 STRATFORD

The net capacity of the Stratford plant is estimated as 210 MW.

3.1.6.14 TARANAKI COMBINED CYCLE

The net capacity of the Taranaki CCGT plant is estimated as 377 MW.

3.1.6.15 TE RAPA

The net capacity of the Te Rapa plant is estimated as 44 MW.

3.1.6.16 WHIRINAKI

The net capacity of the Whirinaki plant is estimated as 155 MW.

3.1.7 AVAILABILITY FACTOR

The MBIE and WSP have defined “Availability Factor” as the “percentage of time plant is available to generate”.

This definition is consistent with the use of the term “availability” in the industry

Many NZ generators have adopted the following Generation Availability Data System (GADS) metrics to monitor and report on generation plant performance internally:

- Equivalent Availability Factor (EAF).
- Forced Outage Factor (FOF).
- Start Reliability Factor (SRF).
- Fuel Conversion Efficiency Factor (FCEF).
- Service Factor (SF).

The Generating Availability Data System (GADS) is a database produced by the North American Electric Reliability Corporation (NERC). It includes annual summary reports comprising the statistics for power stations in the United States and Canada. GADS is the main source of power station outage data in North America.

Many generators in NZ use GADS to measure and monitor their ongoing plant performance and also use this recognised standard of reporting, to benchmark themselves against other similar thermal generation plant globally. As the thermal generation fleet in NZ is relatively small, having a wider pool of similar plant to benchmark performance against is important.

3.1.7.1 BREAM BAY PEAKER

Given available information WSP recommends a value of 85%.

3.1.7.2 EDGECUMBE

Given available information WSP recommends a value of 80%.

3.1.7.3 GLENBROOK

Given available information WSP recommends a value of 80%.

3.1.7.4 HAWERA (WHAREROA POWER)

Given available information WSP recommends a value of 85%.

3.1.7.5 HUNTLY UNITS 1, 2 & 4

Huntly Gas

Genesis Energy has declared the availability of Huntly units 1, 2 & 4, to be 60 – 90% depending on the type of maintenance outage requirements in a particular year.

Assuming 60% availability in the Major Survey year and 90% in the other years results in an average long-term availability of 83%. WSP recommends this value for the GEM.

Huntly Coal

WSP estimates that the availability of Huntly units 1, 2 & 4 when firing coal will be lower than when firing natural gas. This is because more auxiliary equipment is required for coal fuel delivery and preparation, and ash removal and disposal. Coal firing is also somewhat more onerous or 'harder' on the boiler than firing natural gas. The units would therefore be expected to have higher forced outage rates and more unplanned maintenance downtime when firing coal.

WSP estimates an average long-term availability of 78% for Huntly coal units 1, 2 & 4.

3.1.7.6 HUNTLY UNIT 6

Genesis Energy has declared the availability of Huntly Unit 6 (P40) to be 50 – 96% depending on the type of maintenance outage in a particular year. WSP estimates that the lower availability of 50% will only occur every 5 years, resulting in a long-term average availability of 87%.

3.1.7.7 HUNTLY UNIT 5

Genesis Energy has declared the long-term availability of Huntly Unit 5 (e3p) to be 90 – 95% depending on the type of maintenance outage in a particular year. WSP recommends that the median value is assumed for the GEM, 93%.

3.1.7.8 JUNCTION ROAD

Given available information WSP recommends a value of 85%.

3.1.7.9 KAPUNI

Given available information WSP recommends a value of 85%.

3.1.7.10 KINLEITH

Oji has not declared the availability of Kinleith cogeneration plant. WSP estimates this to be similar to Huntly Power Station, units 1 – 4 and recommends a value of 80% for the GEM.

3.1.7.11 MANGAHEWA

Given available information WSP recommends a value of 85%.

3.1.7.12 MCKEE

Given available information WSP recommends a value of 85%.

3.1.7.13 STRATFORD

The following plant availability information was provided by Contact Energy from their FY20 Full Year Results Presentation[7]. This information covers their peaker plants – Stratford, Te Rapa and Whirinaki:

Peakers (including Whirinaki)

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue	
					($/MWh)	($m)
FY17	360	95%	16%	495	73	36
FY18	360	87%	17%	530	116	62
FY19	360	79%	7%	212	192	41
FY20	360	88%	9%	295	162	48

Given available information WSP recommends a value of 85%.

3.1.7.14 TARANAKI COMBINED CYCLE

The following plant availability information was provided by Contact Energy from their FY20 Full Year Results Presentation[7]. This shows over the past 4 years TCC has had an Availability Factor ranging between 63% and 90% due to various factors:

Taranaki combined cycle (TCC)

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue	
					($/MWh)	($m)
FY17	377	90%	31%	1,021	64	65
FY18	377	68%	32%	1,071	102	110
FY19	377	63%	31%	1,031	115	117
FY20	377	88%	26%	870	120	104

Given available information WSP recommends a value of 85%.

[7] https://contact.co.nz/aboutus/investor-centre/reports-and-presentations#Annual-and-half-year-reports

3.1.7.15 TE RAPA

The following plant availability information was provided by Contact Energy from their FY20 Full Year Results Presentation[7]:

Te Rapa (spot generation only)

	Net capacity (MW)	Availability (%)	Capacity factor (%)	Electricity output (GWh)	Pool revenue	
					($/MWh)	($m)
FY17	41	98%	63%	226	58	13
FY18	41	87%	59%	211	94	20
FY19	41	96%	54%	195	160	31
FY20	41	98%	73%	184	106	21

Given available information WSP recommends a value of 85%.

3.1.7.16 WHIRINAKI

Given available information WSP recommends a value of 85%.

3.1.8 UNIT LARGEST PROPORTION

This parameter is defined by MBIE as the “largest proportion of a station output carried by a single unit” and is expressed as a percentage. The data sources for the unit largest proportion were a combination of publicly available information and discussions with operators. Such data can be presented in tabular form as follows.

Table 3-11 Unit largest proportion

Generator	Net operational capacity, MW	No. of units	Unit largest proportion
Bream Bay Peaker	9	5	20%
Edgecumbe	10	2	50%
Glenbrook	112	2	50%
Hawera (Whareroa Power)	68	5	20%
Huntly Unit 5	385	1	100%
Huntly Unit 6	44	1	100%
Huntly Units 1, 2 & 4	750	3	33%
Junction Road	100	2	50%
Kapuni	25	4	25%
Kinleith	38	1	100%
Mangahewa	9	3	33%
McKee	100	2	50%
Stratford	210	2	50%
Taranaki Combined Cycle (TCC)	377	1	100%
Te Rapa	44	1	100%
Whirinaki	155	3	33%

3.1.9 BASELOAD

This parameter is simply a "yes/no" determination of "whether the plant is designed to be operated near/or at full capacity most of the time".

WSP has taken the approach that all thermal generation plant that is not specifically designed and installed as peak load (peaker) plant, is designed to be operated at full capacity all of the time it is available.

Such data can be presented in tabular form as follows.

Table 3-12 Thermal generation plant operation designation

Generator	Design generator function	Baseload	Peaker	Comments
Bream Bay Peaker	Generator	NO	YES	Used as a peaker
Edgecumbe	Cogenerator	YES	NO	Has limited peaking capacity
Glenbrook	Cogenerator	YES	NO	Has limited peaking capacity
Hawera (Whareroa Power)	Cogenerator	YES	NO	Has limited peaking capacity
Huntly Unit 5	Generator	YES	NO	Increased 2 shifing likely
Huntly Unit 6	Generator	YES	NO	
Huntly Units 1, 2 & 4	Generator	YES	NO	With periods of 2 shifting
Junction Road	Generator	NO	YES	With periods of base load generation
Kapuni	Cogenerator	YES	NO	
Kinleith	Cogenerator	YES	NO	
Mangahewa	Generator	YES	NO	
McKee	Generator	NO	YES	With periods of base load generation
Stratford	Generator	NO	YES	Can run for extended periods at base load
Taranaki Combined Cycle (TCC)	Generator	YES	NO	
Te Rapa	Cogenerator	YES	NO	Has limited peaking capacity
Whirinaki	Generator	NO	YES	Only used in server market conditions

Note that all baseload plants have load following capability and, if operating in 'spinning reserve' mode at less than full capacity, can also pick up a share of peak loads.

It is not normal for conventional (boiler + steam turbine) technology to operate as a peaker because of the time taken for cold or warm starts (hours) and the cost of maintaining the unit in hot standby mode. A notable exception is the single 500 MW gas fired Newport D power station in Newport, Melbourne, Victoria, Australia. This plant was modified specifically to enable it to maintain a hot standby condition and to enable it to start and ramp up to full load more rapidly than the original design provided for. It is understood the plant is able to virtually mimic an OCGT peaker plant.

3.1.10 HEAT RATE

The MBIE have defined this parameter as "for each GJ of Fuel input how many useful (station export) GWh of electricity are generated". What is intended by MBIE here is a measure of the efficiency of conversion of fuel energy to electricity. The appropriate and common industry term for this is heat rate. The term "higher heating value" is the term used synonymously with "gross calorific value" for the higher heating value of a fuel, expressed in energy/mass or volume terms, such as MJ/kg.

WSP has relied on the generator owners for this data (noting that in some cases no data was provided), and such data can be presented in tabular form as follows.

Table 3-13 Thermal generation plant heat rate

Generator	Design generator function	Heat rate, GJ/GWh	Comments
Bream Bay Peaker	Generator	-	
Edgecumbe	Cogenerator	11,500	
Glenbrook	Cogenerator	-	Indeterminate bottoming cycle (no fuel used)
Hawera (Whareroa Power)	Cogenerator	-	
Huntly Unit 5	Generator	7,400	Median of given range
Huntly Unit 6	Generator	10,525	Median of given range
Huntly Units 1, 2 & 4	Generator	10,900	Median of given range
Junction Road	Generator	-	
Kapuni	Cogenerator	-	
Kinleith	Cogenerator	-	
Mangahewa	Generator	11,600	
McKee	Generator	-	
Stratford	Generator	8,907	
Taranaki Combined Cycle (TCC)	Generator	7,400	
Te Rapa	Cogenerator	11,700	Excludes the steam component
Whirinaki	Generator	10,906	

The HHV heat rates expressed above can be assumed to reflect the operating regime of the particular plant. That is, they can be assumed to be long term averages and to include the depreciating (heat rate increase) effects of multiple start-ups (for peak load plant) and load following operation at less than full load or maximum continuous rating (MCR).

3.1.11 VARIABLE O&M COSTS

3.1.11.1 INTRODUCTION

These are the non-fuel operational and maintenance costs that are dependent on plant output. Fuel cost is directly proportional to output but is treated separately by MBIE in its modelling suite and is outside the scope of this report.

The 2011 WSP report referred to the GEM 2009 variable and fixed O&M costs. These are as set out in the following table referred to as "GEM 2009 values". It is these values that this report seeks to review and either validate/verify or revise. The AEMO 2018 variable and fixed O&M costs values are also provided below for reference (noted figures converted from original AUD using exchange rates stated in this report).

The GEM values have been indexed using the labour indices; Professional, Technical, Administrative and Support Service from Statistics NZ using the latest available reference point of Q1 2020.

Table 3-14 Thermal generation plant O&M costs (NZD)

Asset	*Techn-ology*	*2011 report recommended GEM values*		*WSP Recommended GEM 2020 Q1 indexed values*		*AEMO 2018 values (for reference)*	
		Variable $/MWh	*Fixed $/kW/yr*	*Variable $/MWh*	*Fixed $/kW/yr*	*Variable $/MWh*	*Fixed $/kW/yr*
TCC	*CCGT*	*4.25*	*35*	*5.2*	*41*	*8.0*	*11.4*
Huntly unit 5 (E3P)	*CCGT*	*4.25*	*35*	*5.2*	*41*	*8.0*	*11.4*
Huntly unit 6 (P40)	*OCGT*	*8.0*	*16*	*9.7*	*19*	*4.6*	*11.5*
Huntly PS (Units 1-4)	*ST (Coal)*[8]	*9.6*	*70*	*11.6*	*82*	*3.6*	*52.6*[8]
Whirinaki	*OCGT (liquid)*	*9.6*	*20*	*11.6*	*23*	*4.6*	*11.5*

GEM overview

https://www.emi.ea.govt.nz/Wholesale/Tools/GEM

We note that Australian thermal generators appear to have generally lower fixed operating costs than the figures estimated for New Zealand thermal generators. Investigation of the reasons for this are outside the scope of this study, however the previous WSP report commented that a significant contributor to the lower values in Australia is thought to be simply economies of scale. Australia has around 48 GW of thermal capacity (including reciprocating engines), compared to around 3 GW in New Zealand.

3.1.11.2 DEFINITION

For the purposes of this report variable O&M costs are defined as follows.

"These costs, defined as $/MWh, refer to the incremental operations and maintenance costs incurred upon increasing the level of production by one unit. Variable O&M (VOM) costs will include

[8] Figures based on an average of gas and coal since Huntly Units 1, 2 & 4 are dual fuel generators

minor unplanned maintenance, water usage, chemicals, limestone (where FGD is used), auxiliary energy use and ash disposal costs.

Major maintenance costs for gas turbine plant can also be included in the VOM cost values. This is because maintenance is based on the equivalent operating hours of the plant as opposed to coal fuelled steam turbine plant where maintenance is periodic and treated as a fixed operating cost. Where the reference information allows, the report will indicate whether major maintenance has been included in the variable or fixed portion of gas turbine plant O&M costs.

Typically, gas fired plant has the lowest variable O&M costs and coal fuelled plant has the highest costs associated with the costs of ash disposal and requirements for flue gas desulphurisation (FGD)."

3.1.11.3 VALIDATION DATA SOURCES

WSP had expected to rely on information provided by the generator owners to validate the GEM O&M cost data. However, the generator owners have advised that this information cannot be provided as it is considered commercially sensitive and confidential.

Variable O&M (VOM) costs have therefore been estimated by indexing the figures from the previous WSP report using the labour indices Professional, Technical, Administrative and Support Service from Statistics NZ.

3.1.11.4 CONCLUSIONS

The following table records the results of the above approach. The dollar values are considered generally equivalent real 2020 New Zealand dollars.

The figures from GEM were indexed using the labour indices Professional, Technical, Administrative and Support Service from Statistics NZ. However, it should be noted that in recent years there has been large increases in costs due for health& safety which WSP believe aren't being fully capture in the indices.

Table 3-15 Previous and 2020 Recommended GEM variable operating costs (VOM), NZD/MWh

Generator	Design generator function	Technology	VOM, NZ$/MWh 2011 report values	VOM, NZ$/MWh 2020 Q1 values	Comments
Bream Bay Peaker	Generator	Recip		14.2	New plant
Edgecumbe	Cogenerator	OCGT	4.2	4.9	
Glenbrook	Cogenerator	Coal (steam)	8.2	9.6	
Hawera (Whareroa Power)	Cogenerator	OCGT	4.3	5.1	
Huntly Unit 5	Generator	CCGT	4.25	5.2	2009 base datapoint
Huntly Unit 6	Generator	OCGT	8	9.7	2009 base datapoint
Huntly Units 1, 2 & 4	Generator	Gas (steam) Coal (steam)	8.2 9.6	9.6 11.6	2009 base datapoint 85% of Huntly coal
Junction Road	Generator	OCGT		9.4	New plant
Kapuni	Cogenerator	CCGT	4.3	5.1	
Kinleith	Cogenerator	Biomass (steam)	8.2	9.6	
Mangahewa	Generator	Recip	12.1	14.2	
McKee	Generator	OCGT		9.4	New plant
Stratford	Generator	OCGT	8.0	9.4	
Taranaki Combined Cycle (TCC)	Generator	CCGT	4.25	5.2	2009 base datapoint
Te Rapa	Cogenerator	GT	4.2	4.9	No steam turbine
Whirinaki	Generator	OCGT (diesel)	9.6	11.6	2009 base datapoint

The accuracy of the above and other costs estimates in this report is estimated to be ± 30% at best and could be up to ± 40%. The reasons for such apparently "inaccurate" estimates relate to the manner in which the estimates have been developed, and in particular WSP's reliance on overseas data and industry indexes, as opposed to actual costs provided by the generator owners.

3.1.12 *FIXED O&M COSTS*

3.1.12.1 INTRODUCTION

These are the non-fuel operational and maintenance costs that are dependent on plant size.

The fixed O&M (FOM) costs presently used in the GEM are those recommended by WSP in its report to the Electricity Commission, “Thermal Power Station Advice - Fixed & Variable O&M Costs”, September 2009.

The design life of a thermal power station is typically between 25 and 40 years. Over time, a number of mechanisms act together to degrade the performance/availability of a thermal power station including:

- Erosion.
- Corrosion.
- Thermal fatigue.
- Creep.
- Obsolescence/unavailability of spares.

In the current market, there is an increasing trend to extend the operating life of power stations beyond their original design life. In addition to normal maintenance, significant refurbishment may be necessary. In addition, it is likely that there will be increasing pressure on thermal generators to reduce their CO_2 emissions.

An example of regular maintenance outage requirements:

Aero derivative GE LM6000 OCGT units usually require a “Hot Section” outage after 30,000 running hours (approximately 10 years). After 60,000 hours, a major outage is required. Then the cycle starts over again.

3.1.12.2 DEFINITION

For the purposes of this report fixed O&M costs are defined as follows.

“These costs, defined as $/kW/year, typically include all fixed operating costs such as spares, major periodic maintenance, insurance, O&M fees, property taxes and leases and owner’s costs such as wages. Fixed costs should not vary with changes in electricity generation levels.”

3.1.12.3 VALIDATION DATA SOURCES

WSP had expected to rely on information provided by the generator owners to validate the GEM O&M cost data. However, the generator owners have advised that this information cannot be provided as it is considered commercially sensitive and confidential.

Fixed O&M (FOM) costs have therefore been estimated by indexing the figures from the previous WSP report using the labour indices Professional, Technical, Administrative and Support Service from Statistics NZ.

3.1.12.4 CONCLUSIONS

The following table records the results using the above approach.

Table 3-16 Previous and 2020 Recommended GEM fixed operating costs (FOM), NZD/kW/y

Generator	Design generator function	Technology	FOM, NZ$/kW/y 2011 report values	FOM, NZ$/kW/y 2020 Q1 values	Comments
Bream Bay Peaker	Generator	Recip		19	New plant
Edgecumbe	Cogenerator	GT	30	35	
Glenbrook	Cogenerator	Coal (steam)	70	82	
Hawera (Whareroa Power)	Cogenerator	OCGT	16	19	
Huntly Unit 5	Generator	CCGT	35	41	2009 base datapoint
Huntly Unit 6	Generator	OCGT	16	19	2009 base datapoint
Huntly Units 1, 2 & 4	Generator	Gas (steam) Coal (steam)	60 70	70 82	85% of Huntly coal 2009 base datapoint
Junction Road	Generator	OCGT		19	New plant
Kapuni	Cogenerator	CCGT	35	41	
Kinleith	Cogenerator	Biomass (steam)	60	70	
Mangahewa	Generator	Recip	16	19	
McKee	Generator	OCGT		19	New plant
Stratford	Generator	OCGT	16	19	
Taranaki Combined Cycle (TCC)	Generator	CCGT	35	41	2009 base datapoint
Te Rapa	Cogenerator	GT	30	35	
Whirinaki	Generator	OCGT (diesel)	20	23	

3.1.13 FUEL DELIVERY COSTS

3.1.13.1 INTRODUCTION

WSP's report, "Thermal Power Station Advice, Report for the Electricity Commission", July 2009 recorded the fuel prices assumed for the long run marginal cost (LRMC) calculations. These were reported under the heading, "generic assumptions" and included the note that "the modelling . . . excludes fuel delivery costs." This section reviews the cost of fuel transmission, distribution and/or transport logistics.

WSP's most recent study of fuel costs for power generation that included fuel transport costs, is understood to be its report to the Electricity Commission, "Electricity Generation Database Statement of Opportunities Update 2006", October 2006. The conclusions of that report are reproduced in the following sections for comparison.

With the exception of Kinleith, Glenbrook, and Mangahewa the thermal generators are all fuelled with one or more of three fuels:

- Natural gas
- Coal (Huntly coal units 1, 2 & 4 only)
- Diesel (Whirinaki and the Bream Bay Peaker)

Kinleith and Glenbrook are fuelled with by-product or waste streams from their cogeneration hosts and are considered to have a zero-fuel cost and zero fuel delivery costs, as the fuels are produced on site.

Mangahewa is fuelled by raw wellstream gas rather than pipeline gas.

3.1.13.2 NATURAL GAS

WSP's Electricity Generation Database Statement of Opportunities Update 2006 report concluded with respect to gas transport costs as follows.

"There is an additional cost for transporting gas north of Huntly after the gas leaves the Maui gas pipeline and is transported in the high-pressure pipelines owned by First Gas (formerly Vector, Natural Gas Corporation)."

The gas transmission prices comprise three components:

1. A "Capacity Reservation Charge" which reflects the asset costs (return and depreciation) of an optimal transmission system. These fees are calculated in \$/GJ of reserved capacity. These are fixed charges, recovered whether or not the full Maximum Daily Quantity (MDQ) is used.
2. An "Overrun Charge" that applies to deliveries made in excess of reserved MDQ. These fees are set at a level to create incentives for customers to reserve MDQ as accurately as possible. The fees are avoidable by reserving sufficient capacity to meet short term peak requirements or obtaining additional capacity entitlements through the secondary market.
3. A "Throughput Charge" that recovers all other operating costs. As an example, Contact Energy provided the following updated gas transmission cost for:

– TCC and Stratford Peakers is ~\$0.44/GJ

– Te Rapa is ~\$0.79/GJ

Natural Gas Underground Storage:

The Ahuroa Gas Storage Facility in Taranaki was officially opened in 2011 with a development cost of $177m. In 2017, Contact Energy sold the gas storage facility to Flex Gas, a subsidiary of First Gas.

This underground natural gas storage facility is used to supply local power generation facilities and other major users of gas during periods of peak demand. This underground facility can store up to 18 PJ of natural gas, with injection rates up to 27 terajoules per day and withdrawal rates of up to 45 terajoules per day. There are plans to expand this storage facility to enable 65 TJ of natural gas per day to be injected and withdrawal from the storage facility by 2021.

3.1.13.3 COAL

Currently Genesis Energy's Huntly Rankine units 1, 2 & 4 are the only thermal generation units able to exclusively use coal fuel (although usually a combination of coal and natural gas fuel is used).

These units can use a combination of locally sources coal and international imported coal which meet the tight technical and environmental specifications required for the Huntly boilers.

Availability of local coal supplies has required Genesis Energy to continue to purchase coal supplies from overseas coal suppliers. These overseas coal supplies have been secured over past years on long term supply agreements. So far, all imported coal has been obtained from selected mines in Indonesia.

Coal imported from Indonesia for Huntly Power Station is discharged from ships at the Port of Tauranga. Coal is stored at Mount Maunganui in a large storage facility, before being transported to Huntly.

While imported Indonesian coal was initially only transported to Huntly Power Station by truck, rail proved to be a lower cost option. Specially built rail wagons were built for Genesis Energy and rail has been used as the preferred imported coal transport option since 2004.

The imported coal is still required to be trucked from the rail stockout facility at Rotowaro to the Huntly West Mine stockpile area or directly into the coal conveyor truck hoppers at this site. From these hoppers, coal can be feed onto the 5km long over-land coal conveyor system to the Huntly Power Station site. Coal can be stockpiled if not required for planned generation purposes or conveyed directly to the unit coal bunkers.

A stockpile bend of local and imported coal is often used (depending on available coal supplies) and this bended coal is delivered to the Rankine units coal bunkers to meet planned short-term generation production outputs. Coal cannot be stored long-term in the coal bunkers due to fire risks.

So overall there are considerable logistics and costs involved with the delivery of coal to the Huntly site.

Genesis Energy plans to stop burning coal at Huntly in 2030.

3.1.13.4 DIESEL

The Whirinaki OCGT plant and the Bream Bay Peaker plant are the only generators exclusively using diesel fuel.

WSP's Electricity Generation Database Statement of Opportunities Update 2006 report concluded with respect to diesel transport costs as follows.

"At full capacity over 24 hours the Whirinaki plant will use approximately 1M litres of diesel per day. Whirinaki's fuel supply held is at two onsite tanks and two bulk storage tanks off-site near the Port of Napier. The onsite tanks will be kept nominally full and are able to hold approximately 4.2M litres of fuel."

The cost of diesel for generation purposes is estimated to be NZ$1.30 per litre at October 2020, which is estimated to be made up of a purchase price of NZ$1.20 per litre and a delivery cost of NZ$0.10 per litre. Based on an energy content of 37.1MJ per litre (net) the delivery cost equates to $2.66/GJ.

4 FUTURE PROPOSED THERMAL GENERATING PLANT DATA

4.1 SUMMARY

Table 4-1 Currently proposed thermal generation plant

Plant	Capacity (MW)	Fuel Type	Operator
Proposed			
Waikato Power Plant	360	Natural Gas	Todd Generation Taranaki

The previous WSP report contained recommendations on the potential operation, associated costs, and life of proposed thermal plants in New Zealand. Information on the variables as summarised in Table 4-1 of the previous WSP report have been requested by MBIE for any plants classified as "Under construction" or "Proposed" in the table above for the 2020 update. Therefore, the Waikato Power Plant is the only thermal generation plant considered in this section.

The following describes the Waikato Power Plant and lists the updated technical and cost estimates gathered from various sources in tabular form.

Waikato Power Plant (WPP)

Todd Generation Taranaki Ltd. is proposing to build a $350 million, 360 MW open cycle gas turbine power plant on a site located in the Tihiroa area, near Otorohanga in the Waikato.

The plant is likely to be built in a similar configuration to Todd Generation Taranaki Ltd.'s current McKee and Junction Road OCGT plants in Taranaki. WPP is expected to be developed in stages with an overall capacity of 360MW consisting of 6 x 60WM OCGT's. The first stage is expected to have a capacity of 120MW (e.g. 2 x 60MW GE LM6000 OCGT units).

The proposed plant would be fuelled by natural gas from the adjacent Maui gas transmission pipeline. A local grid connection would be required.

The plant was granted resource consent in May 2017. The consent allows for a 10-year lapse period to begin construction. The firm also received land use consent for 35 years.

General feedback from discussions with Todd Generation Taranaki Ltd in the course of preparing this report is that the likely timing of this project is not able to be advised, given the current market conditions, Tiwai closure uncertainty, carbon tax implications, and the bedding in of their recently commissioned Junction Road plant.

The expected lifecycle for WPP would be similar to the Junction Road power plant (37 years as per the assumptions of section 3 above).

Table 4-2 Technical and Cost Estimate Data for Proposed Thermal Plant

Project name	Plant Tech	Energy Type	Substation	Project lifetime	Capacity	Availability Factor	Unit Largest Proportion	Base load	Heat Rate (HHV)	Variable O&M Costs	Fixed O&M Costs	Fixed Delivery Charge	Capital Cost NZD component	Capital Cost Foreign	Dominant Foreign Currency	Lines Connection Cost
				Years	*MW*	*%*	*%*	*Y/N*	*GJ / GWh*	*$ / MWh*	*$ 000 / MW / year*	*$ / GJ*	*$ / kW*	*Currency / kW*		*$ m*
Waikato Power Plant	OCGT	Gas	New tbc	50	360	87	16.7	N	11,750 max operation 37,500 min operation (AEMO)	11.4	4.6	1	464	567	USD	5

Notes on assumptions relating to the above table:

- The specific capital costs in the GEM Input Data spreadsheet are in a field titled, “Capital cost, foreign currency per kW”, however the data in the field is understood to be the total specific capital cost.
- The dominant foreign currency will depend on which country or countries the major equipment is sourced from. This is not readily determined because there are competing OEMs (original equipment manufacturers) located in different countries for all the planned thermal generator technologies. The above has assumed GE turbines similar to Todd’s Junction Road plant recently built and assumed to be supplied out of the US therefore the dominant foreign currency used is USD.
- Location assumption for lines connection cost: the WPP is likely to be located close to a convenient gas supply point.

Validation data sources

In developing its recommendations, WSP has referred to information obtained through consultation with generators, in-house data and the following additional sources:

- Australian Energy Market Operator (AEMO) costs and technical parameter review Report 9110715 Rev 4 September 2018.
- UK Department for Business, Energy and Industrial Strategy (BEIS) Generation Costs Report November 2016, which in turn referenced:
  - NERA Economic Consulting, 2016, Electricity Generation Costs and Hurdle Rates: Lot 1: Hurdle Rates for Generation Technologies.
  - DECC 2015, Periodic Review of FITs 2015 (Impact Assessment).
  - Parsons Brinckerhoff 2015 (for DECC), Small Scale Cost Generation Costs Update.
  - Leigh Fisher & Jacobs, 2016, Electricity Generation Costs and Hurdle Rates: Lot 3: Non-Renewable Technologies.

4.1.1 GENERAL UPDATE OF POTENTIAL THERMAL PLANT

As a general update to the proposed future thermal plant options contained in the 2011 WSP report, we have taken the main options considered at the time such as potential, Huntly repowering, and other new potential thermal plant options since the 2011 report, and have generalised them into the following summary.

Table 4-3 Potential future thermal generation plants

Generator	Capacity MW	Fuel Type	Location	Ownership
Waikato Power Plant (WPP)	360	Natural Gas	Otorohanga	Todd Generation
Huntly Repowering	400	Natural Gas	Waikato	Genesis Energy
Cogen 1	50	Natural Gas / Biogas	TBC	TBC
Hydrogen 1	500	Hydrogen	TBC	TBC

Huntly Repowering

In December 2016, Genesis received consents to replace its Rankine units any time during the subsequent 20 years with gas-fired generation. This could include the installation of four open-cycle gas turbines of around 100 MW each, or eight 50 MW units in two stages, or a combination up to a total capacity of 400 MW.

Cogen 1

Further refurbishments, replacements of existing, or new build cogeneration plants remain a possibility in the forward time frame, and would seem likely to be predominantly biogas, biodiesel or conventional gas based plants depending of resilience of supply.

The Cogen 1 option is assumed to be a 50 MW single unit, CCGT cogeneration generator. This would be located at the site of the cogeneration heat load (steam consumer) host and would also likely to be located at either a convenient gas supply point, a convenient transmission connection, or a combination of both.

Although not considered highly likely, the possible future plants in this category would be envisaged to be similar to existing cogeneration plants at Hawera, Kapuni and Edgecumbe.

Hydrogen 1

While not strictly a new generation, the option of converting existing gas fired thermal plants to hydrogen supplemented, or new build fully hydrogen fired plants is considered to be a potential future possibility. Many existing gas plants can operate on up to around 5% hydrogen and the majority of international gas turbine equipment suppliers have committed to developing gas plant that is capable of operating with increased levels of H2, to levels nominally around 20% in the near term and up to 100% by 2030. This opportunity for potential use of hydrogen thermal plant as a renewable option will be dependent on the development of a 'green' hydrogen supply infrastructure in NZ and/or internationally.

5 FUTURE GENERIC PLANT DATA

This section provides technical specifications and cost estimates for a range of generic projects that may provide future generation post-2020 and out to 2060. This information is needed to ensure that there is a broad evidence base available for wider modelling purposes, and is not an indication of policy direction, nor endorsement or otherwise of any technology.

Although it is not expected that a significant amount of new thermal generation will be built in the future, some may be required for electricity security of supply, and it would be expected that any such plant would be fuelled by natural gas. It is possible that new thermal plants could incorporate carbon capture and storage (CCS) technology. As a result, MBIE have requested updated estimates of the expected cost of new natural gas plants both with and without CCS technology.

Refer to the below table for the information requested by MBIE to be provided for these generic new natural gas plants:

Table 5-1 Future generic thermal generation plant data

VARIABLE	PEAKING	BASELOAD
Technology	Open cycle gas turbine (OCGT)	Combined cycle gas turbine (CCGT)
Fuel	Natural gas	Natural gas
Capacity, MW	100	300
Number of units	1	3
Availability factor, %	87	93
Heat rate, GJ/GWh	11,750 at max operation (AEMO) 37,500 at min operation (AEMO)	7,580 at max operation (AEMO) 16,590 at min operation (AEMO)
Plant without CCS		
Capital cost, $/MW	$1,030,000 (AUD 950,000)	$1,305,000 (AUD 1,200,000)
Fixed operating costs, $/kW/year	$4.6 (AEMO AUD 4.2)	$11.4 (AEMO AUD 10.5)
Variable operating costs, $/MWh	$11.4 (AEMO AUD 10.5)	$8.0 (AEMO AUD 7.4)
Plant with CCS		
Capital cost, $/MW	$4,650,000 (BEIS GBP 2,350,000)	$1,570,000 (AEMO AUD 1,440,000)
Fixed operating costs, $/kW/year	$62.4 (BEIS GBP 31.8) *(assuming 2000 hrs / year)*	$19.5 (AEMO AUD 17.9)
Variable operating costs, $/MWh	$5.9 (BEIS GBP 3)	$13.7 (AEMO AUD 12.64)

Sources:

- Discussions with NZ Power Generation Plant owners and WSP Thermal team
- Australian Energy Market Operator (AEMO) costs and technical parameter review Report 9110715 Rev 4 September 2018. Reference for the OCGT without CCS, CCGT without CCS, and

CCGT with CCS figures. The AEMO report was used as the data basis for these technologies based on advice from WSP thermal technical specialist, and because we understand that this data best provides up to date information relevant to the Australasia region. However please note the AEMO report did not include figures for the OCGT with CCS technology category.

- UK Department for Business, Energy and Industrial Strategy (BEIS) Generation Costs Report November 2016. Reference for the OCGT with CCS figures. The BEIS report did provide a figure for OCGT with CCS, therefore this was used for the purposes of this report. The figures provided are based on a 2025 commissioning date and the 'medium' range figure.

Note on the above table:

- These generic projects are based on the defined generic plant categories and are not intended to be representative of all future generation alternatives. The list is not a view or opinion of what will be built over the modelling period or what type of plant has a greater probability of being built.
- The decision to build new generating plant depends on a wide range of complex technical and commercial factors, only some of which are considered in this report. It is also important to note that actual generation plant technical and cost parameters will vary widely and hence the estimates provided in this report are intended only as a concept level guide.
- CCS storage (and transportation) costs are the costs associated with the transmission, storage and on-going monitoring of captured CO_2 in a stable geological formation in which it can be sequestered. As no commercial scale storage facilities have been developed in NZ, these costs are indicative estimates compiled from review of a number of public domain sources listed above.

5.1 GENERIC PLANT TECHNOLOGIES

This section identifies the generic thermal plant technologies that may provide future generation post 2020 and out to 2060, based on the following rationale.

'Thermal power generation plant' is the term that describes the technology used for converting the potential chemical energy in combustible materials (fuels) into electricity. In a cogeneration plant the fuel energy is converted into heat and electricity.

Therefore, the consideration of future generic plant must be based firstly on consideration of available fuels and their relative environmental and market costs. These in turn are likely to be impacted by:

- **NZ's net zero emissions targets:** in 2019 the Government introduced the Climate Change Response (Zero Carbon) Amendment Bill, setting a target of net-zero carbon emissions by 2050. We expect that the extent of changes in electricity sector technology and market decisions of which technologies are developed over the next 30 years will be a crucial factor and driver in determining the path of decarbonisation in NZ.

- **Carbon price increases** Carbon prices are expected to increase from NZD$25 per tonne of carbon dioxide in 2020 to NZD$66 per tonne by 2050[9]. This assumption is in line with IEA's Current Policies Scenario for the European Union to align New Zealand's carbon prices with its trading partners. In the IEA's 'Environmental' scenario, carbon prices rise to NZD$154 (USD$100) per tonne by 2050.

At the time of writing, WSP considers the potentially available fuels for power generation or cogeneration in the future, post 2020 are:

- Indigenous natural gas, assuming that there may be new discoveries within existing consented fields and existing fields remain productive.
- Imported liquefied natural gas (LNG).
- Biomass, comprising both forestry industry waste and plantation grown fuel species.
- Biogas, as landfill gas and biogas from sewage treatment, waste food anaerobic digester (AD) plants assuming population growth gives rise to growth in resources.
- While diminishing in use as NZ heads towards net zero emissions, petroleum liquid fuels, ranging from crude oil to automotive diesel and including heavy fuel oil (HFO) may still be required in the fuel mix for capacity and emergency peaking power supply.
- Hydrogen, both "Green Hydrogen" utilising renewable energy and Grey/Blue Hydrogen utilising nature gas fuels, with or without CCS.
- Indigenous natural gas to fuel Allam-Fetvedt Cycle – electricity generation / hydrogen production plants.

Given those fuels, the following are considered as the future generic plant technology options for New Zealand:

- Combined cycle gas turbine (CCGT) baseload generation, using indigenous natural gas, LNG or Hydrogen
- Open cycle gas turbine (OCGT) peaking generation, using indigenous natural gas, LNG or Hydrogen
- Reciprocating engines, using biofuels such as landfill gas and biogas from sewage treatment and food waste Anaerobic Digester (AD) Plants, in a base load or 'fuel following' (analogous to 'run-of-river' hydro generation) role
- Biomass cogeneration using forestry industry waste and/or plantation grown fuel species.
- Allam-Fetvedt Cycle – hydrogen, generation and pipeline CO2 production.
- The above future generic options all assumed to be installed with CCS or with future proofed capability to include CCS where possible through technology developments.

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[9] MBIE, Electricity demand and generation scenarios, July 2019

5.2 FUTURE GENERIC THERMAL PLANT DISCUSSION

5.2.1 CCGT

In the 2011 WSP report options for the most effective and optimally located sites for a future large scale CCGT were identified as the decommissioned Marsden A&B power station, Rodney, Otahuhu C, Huntly expansion/repowering or the decommissioned site of the New Plymouth Power Station.

In this 2020 update WSP believe these options and locations around the North Island would remain the most effective and optimal. These sites are either already connected to both natural gas supplies and the electricity transmission system or would have relatively low barriers to re-establishing connections to these systems.

5.2.2 OCGT PEAKER

Other than the proposed OCGT Waikato Power Plant peaker generator and possible Bream Bay diesel peaker plant expansions discussed above, the main locations identified as most effective and optimal for OCGT peakers would be: gas fuelled OCGT plant(s) located adjacent to major substations serving the main North Island load centres at Auckland, Hamilton, and Wellington, (and located adjacent to existing gas distribution).

5.2.3 CARBON CAPTURE AND STORAGE (CCS)

CCS is expected to have a significant impact on the costs of any CCGT or OCGT power plant constructed in NZ (and internationally) in the future. The following comments are taken from various references referred to elsewhere in this report and listed in Appendix A.

The UK Department for Business, Energy & Industrial Strategy (BEIS) Electricity Generation Costs Report November 2016 provides notes for the Carbon Capture and Storage (CCS) estimates provided for First of a Kind ('FOAK') and Nth of a Kind ('NOAK') implementation. For these technologies with no commercial experience, FOAK was defined as the first plant within the UK, not including demonstration projects. For these technologies, FOAK costs assume experience has been gained from international and demonstration projects. CCS in particular is a new technology and costs are therefore inherently more uncertain than established technologies with a proven track record. In addition, CCS costs depend not only on the characteristics of individual plants, but also the extent to which transport and storage infrastructure is shared between them. Some FOAK plants may be able to adapt existing oil and gas facilities, but others may have to build new infrastructure for transport and storage.

The basis for estimates for Carbon Capture and Storage (CCS) presented in the BEIS document above are intended to illustrate the cost of CCS for a commercial plant. In practice CCS would have be successfully demonstrated first. We have not included estimates for the costs for initial CCS demonstration projects.

The Leigh Fisher Ltd Energy Generation Costs and Hurdle Rates Report August 2016 notes that: There have been numerous studies on cost reductions in CCS. This is a highly uncertain area, as CCS plants are still largely in demonstration phases. Regarding CCS transportation it is noted that here may be opportunities to reduce the costs of the transport and storage infrastructure by using existing infrastructure developed by the oil and gas industry that is no longer in use, such as pipelines. Multiple CCS plants could also share a pipeline or storage facility to benefit from economies of scale.

In the previous WSP report it was noted that the three main technology options for CO2 capture are post-combustion capture through capturing CO2 from flue gas, pre-combustion capture by separating the carbon from the fuel before burning it, and oxy-combustion under an oxygen atmosphere resulting in flue gases consisting of mostly CO2 for final storage. These technologies have been applied for many years in large scale plants however the integration of the different components needed to capture CO2 in power plant design is still in the development phase. Also, the integrity of the various methods to store CO2 has to be verified. In addition legal and regulatory issues related to the transport and storage of CO2 have to be addressed in many countries. Please refer to the previous WSP report for further details.

Commentary on the developments since the 2011 report have generally been that while a the myriad of new solutions provide great opportunity for CCS in NZ, practical difficulties exist including geological, reliability and financial barriers (extracted from the Productivity Commission Low emissions economy final report August 2018, refer to this report for full details):

5.2.3.1 CCS SITING

For CCGT and OCGT options with CCS a further siting consideration is added, that of access to a carbon storage reservoir. With respect to storage opportunities, GNS Science in 2011 reviewed potential storage opportunities for onshore and immediate offshore locations in the Waikato region and the onshore Taranaki region.

Reporting through the GNS Globe Magazine, Issue No. 2, August 2011, GNS Science noted that ideally CO2 emissions should be captured at source, turned into a liquid, and stored safely underground in depleted oil and gas reservoirs, however that globally there are limited economic incentives for CCS development and in NZ the potential impact is less than many other higher populated countries with relatively lower renewable energy sources. Their research indicated that NZ has enough underground storage capacity to store captured emissions from large industrial sources over the next 30 years. However in the short term at least, it is considered unlikely that CCS would be associated with coal-fired electricity generation in NZ.

5.2.3.2 CCS EFFECTIVENESS

Regarding CCS efficiencies, the Leigh Fisher Ltd Energy Generation Costs and Hurdle Rates Report August 2016 notes that a broad range of published and internal data have been considered for each of the efficiency estimates, as summarised below:

Table 5-2 Gas CCS efficiency (percentage point reduction)

	Technology type	Estimate
A	CCGT – post combustion	10.9%
B	CCGT – retro post combustion	10.9%
C	CCGT – pre combustion	17%
D	CCGT – oxyfuel combustion	13%
E	OCGT – post combustion	10.9%

5.2.4 RECIPROCATING ENGINE PEAKER

Future reciprocating engine peakers for additional local capacity and emergency backup supply are considered likely to follow a model using diesel fuel and located (embedded) in local distribution network zone substations.

The main population centres appear to be the candidates for diesel fuelled, reciprocating engine peaking plant. It seems likely, if this type of plant is to be used at all, that it will appear in the main cities, Auckland, Wellington, Dunedin, Christchurch, Hamilton, New Plymouth and Tauranga.

WSP estimates that future additions of this type of generic generator will be around 10 MW.

5.2.5 CCGT COGENERATION

As noted above, cogeneration plants are located at or near their process heating (steam) 'hosts' and, in this case, the process heating host will also be located where there is access to either indigenous natural gas, LNG or Hydrogen.

Although not considered highly likely, the possible future plants for CCGT cogeneration plant would be most likely located at large industrial sites in the Waikato and Taranaki regions. This could comprise additional generation capacity at existing sites such as Hawera, Te Rapa and Edgecumbe, or new generators at new industrial sites.

As New Zealand's current natural gas pipeline network only exists in the North Island and reaches out to the following regions/locations: Taranaki, Waikato, Auckland, Whangarei, Bay of Plenty, Taupō, Gisborne, Manawatu, Hastings and wider Wellington. Cogeneration plants requiring large volumes of natural gas may be restricted to locations adjacent to the Maui pipeline route to ensure sufficient gas pressure and capacity is available. Refer to diagram below.

Natural Gas fuelled cogeneration is likely to be restricted to these areas, unless large quantities of alternative thermal fuels can be supplied to other areas economically.

WSP estimates that future additions of this type of generic generator will be in the range of 25 – 50 MW.

5.2.6 BASELOAD / PEAKING

This section considers the generating role the future generic thermal plant options. 'Baseload', according to the North American definition, is anything over a 50% capacity factor, meaning generation at 50% load for 100% of the time, or 100% load for 50% of the time, and every combination in between with a product of 50%.

In New Zealand the term 'baseload' has tended to be used firstly for those generators that run continuously, except for maintenance, up to the maximum capacity allowed by their water, steam or fuel supply. This includes all 'use it or lose it', 'run-of-river' hydro and geothermal plants.

The term 'baseload' is also used for those generators that run generally at constant load and do not follow the daily load curve. In New Zealand this includes significant hydro generation capacity which has limited storage capacity. In Australia and North America this would include a large proportion of coal-fired, conventional thermal generation.

Generators that participate in load following, but are not peakers, have been termed 'intermediate' generators in New Zealand. In North America they would be considered to be baseload.

Peak load generators, or peakers, are those generators that generate only for minutes or hours each day, during the sharpest demand peaks.

The nature of the New Zealand generation system, being predominantly (around 58%) hydro based means that New Zealand is subject to varying climatic conditions and to what has come to be termed, 'wet years' and 'dry years. During 'dry years', intermediate and peaker generating plants will normally generate more, making up for 'dry year' water shortage in the hydro systems.

Most power generation equipment is designed to be operated at its maximum continuous rating (MCR), which is why there is such a term. The gas turbines in OCGT plant and CCGT plant are not dissimilar to the jet engines on aircraft, which are capable of operating at MCR for indefinite periods as long as sufficient fuel is available.

Conventional thermal generation equipment, particularly boilers and steam turbines are usually capable of operating for extended periods at MCR, from 4 – 6 years between major overhauls. They can also operate for more than 365 days without shutting down; however they normally have annual maintenance. Running continuously at MCR is also usually the most economic operating mode. Life can be consumed quicker by cycling than by continuous steady load with this type of plant.

However, most power generation equipment has a finite life between maintenance or overhaul, generally based on operating hours. This is most pronounced for the gas turbines which have mandated inspections and overhauls at clearly defined, thousands of hours, intervals.

5.2.7 HYDROGEN

While not strictly a new generation, the option of converting existing gas fired thermal plants to hydrogen supplemented is considered to be a potential future possibility. Many existing gas plants can operate on up to around 5% hydrogen and the majority of international gas turbine equipment suppliers have committed to developing gas plant that is capable of operating with increased levels of H2, to levels nominally around 20% in the near term and up to 100% by 2030. This opportunity for potential use of hydrogen thermal plant as a renewable option will be dependent on the development of a 'green' hydrogen supply infrastructure in NZ and/or internationally.

International Developments

Currently international companies like Mitsubishi Hitachi Power Systems (MHPS), GE Power, Siemens Energy, and Ansaldo Energia are looking to develop 100% hydrogen-fuelled gas turbines due to new carbon reduction policies worldwide. These companies all currently manufacture large natural gas fuelled gas turbines and can see an emerging opportunity and need for gas turbines capable of being fuelled with increasing percentages of hydrogen.

- MHPS has tested a large number of gas turbine units with hydrogen fuel injection content ranging between 30% and 90%. These tests that have spanned over 3.5 million operating hours on various sized units.
- GE Gas Power offers combustion systems for both aero-derivative and heavy-duty gas turbines that are capable of operating with increased levels of hydrogen fuel mix with natural gas.
- GE and Uniper (an international energy company based in Germany) are planning upgrades to all GE gas turbines and compressors at the German generation giant's gas power plants and gas storage facilities across Europe. These developments will focus on a broad gas turbine fleet which includes LM2500 and LM6000 aero derivative gas turbines, as well as 6F, 9E, 9F, and GT26 heavy-duty gas turbines.

- **Siemens** is looking to offer 25-MW to 50-MW hydrogen-burning gas technology 2022. Since the 1960s more than 55 Siemens units built for a range of industries around the world have combusted fuels with varying hydrogen content.
- Italian engineering firm **Ansaldo Energia** offers fuel-flexible advanced gas turbine combustion systems for the latest GT26 F-Class and GT36 H-Class gas turbine equipment.

5.2.7.1 NZ GREEN HYDROGEN PRODUCTION - REFERENCE PROJECTS

- Halcyon Power Limited's 1.5MW Green Hydrogen production plant at Mokai geothermal power station.
- Ballance Agri Nutrients / Hiringa Energy – Wind powered Green Hydrogen production plant at Kapuni

5.3 ALTERNATIVE FUTURE USES OF EXISTING THERMAL GENERATION SITES / BATTERY PROJECTS

5.3.1 SOUTHDOWN SITE

The site on which the decommissioned Southdown GT thermal generation plant was sited on is now being used as a large scale battery storage facility. With an Auckland location and close access to a grid connection, this has made this an ideal alternative use for this site.

Other sites are likely to be developed during the next 50 years in NZ

5.3.2 OVERSEAS THERMAL GENERATION SITES CONVERSION TO BATTERY

AGL Energy plans to convert its Liddell coal power station in New South Wales into a large scale battery site once it shuts down the plant in the first quarter of 2023.

The generator-retailer intends to install up to 500 MW in battery capacity at Liddell, but it expects the first phase will involve 150 MW by 2024.

6 PLANT COMPONENT COST BREAKDOWN

6.1 THERMAL

The majority of the capital costs of thermal power plants are the generating equipment costs. The estimated breakdown of project capital costs contained in sections 4 and 5 has been expanded to include the major cost components included in Table 6 1. The typical cost breakdown has been based on the generic 400MW CCGT project.

Table 6-1 Thermal generation plant project cost breakdown

Component	% of total Project Capital Cost	Likely Cost Range (% of Total Cost)
Pre-Development	5	3-7
Equipment	60	50-70
Civil Works	15	10-20
Engineering	5	3-7
Owners Costs	10	8-12
Contingencies	5	3-7
Total	100	

Table 6-2 Thermal generation plant component cost breakdown

Component	% of total project capital cost	Likely cost range (% of total cost)
Project		
Pre-Development	5	3-7
Equipment	60	50-70
Civil Works	15	10-20
Engineering	5	3-7
Owners Costs	10	8-12
Contingencies	5	3-7
Total	100	

7 THERMAL PLANT HEAT RATE VS. UTILISATION

For thermal generation plant it is important to understand some core performance measures which will affect the plant over its lifecycle

Heat rate is a measure of fuel conversion efficiency given as fuel energy input per power output.

The primary factors affecting average plant heat rate over the life of a thermal plant are:

- Type of plant.
- Equipment selection.
- Fuel supply type and quality.
- Operational role (frequency of starts, trips, load factor).
- Plant location/environmental factors (e.g. elevation, ambient temperature).

There are some generic principles that apply to understanding how heat rates apply to different thermal plant types.

- Thermal plant heat rates improve as unit size increases.
- As new production models are introduced and existing GT designs are advanced over time, heat rates will improve.
- Typically, new gas turbine designs are conservatively rated when introduced. They are periodically upgraded over the service life to increase power and efficiency (heat rate). Net heat rate gains associated with these upgrades can range up to 7%.
- High efficiency GT models and thermal plant designs command a higher price premium than less efficient machines.
- Heat rates degrade over the service life of thermal plant, with performance losses usually classed as recoverable or non-recoverable. Recoverable losses are typically reduced or eliminated through maintenance and replacement of components. Typical average heat rate degradation for GTs may be between 2% and 6% for the first 24,000 hours of operation.
- When thermal generating plants start-up they use fuel to get the equipment up to operating speed and temperature. Similarly, fuel is used as the plant reduces speed to its coast-down condition. Thus, the more often a plant is started the lower the overall efficiency (higher heat rate) will be.
- When thermal generating plants run at less than full load or maximum continuous rating (MCR), the heat rate tends to increase as the load is reduced. This is particularly so for gas turbines and most pronounced at loads lower than 50% for gas turbines. It is less pronounced for steam turbine plant and generally insignificant for diesel and gas engines (reciprocating engines).

WSP used Thermoflow GTPro to estimate the effects of part loading on the heat rates for selected gas turbines, with the results recorded in Table 7.1 following. WSP confirms this is still valid.

Table 7-1 Gas turbine heat rate change with load factor

Gas turbine plant gross heat rates (kJ/kWh)			
Load condition	OCGT 120MW GE PG9171E	OCGT 162MW Alstom 13E2	OCGT 155MW Siemens V94.2
30%	17,625	16,381	14,253
50%	14,015	12,817	12,412
75%	11,917	11,013	11,262
100% (full load)	10,706	10,018	10,476

WSP recommends the following heat rate performance reductions should be applied to thermal plant for the following load conditions:

Table 7-2 Thermal plant heat rate change with load factor

Thermal plant gross heat rate increases				
Load condition	OCGT 50MW	OCGT 150MW	CCGT 400MW	Coal plant
30%	40%	40%	-	-
50%	15%	15%	15%	5%
75%	5%	5%	5%	2%
100%	-	-	-	-

The HHV heat rates expressed in this report for baseload plant can be assumed to be the long-term average heat rates applying at or around full load or maximum continuous rating (MCR). The heat rates expressed for the peaking plants can be assumed to be long term averages and to include the depreciating (heat rate increase) effects of multiple start-ups. Note that diesel and gas engine plant heat rates are not significantly affected by multiple start-ups and part load operation.

Note that the parameter, "net capacity factor" (NCF) is a very coarse means of adjusting heat rate to make allowance of part load operation. This is because a 50% NCF can represent both 50% load for 100% of the time AND 100% load for 50% of the time, and all combinations between.

8 UNCERTAINTY IN ESTIMATING FUTURE PLANT COSTS

8.1 THERMAL

8.1.1 INTRODUCTION

The references used earlier in this report, in particular for the estimation of O&M and specific capital costs, also contain comment on the uncertainty involved in estimating future plant costs. Given that WSP has relied on those references for its estimation of O&M and specific capital costs, it is relevant to declare the submissions of those same references on the matter of uncertainty.

8.1.2 AEMO, SEPTEMBER 2018

AEMO, September 2018 used the estimation assumptions published by the AACE International guideline for cost estimate classification for the process industries. AEMO, September 2018 notes that:

"The cost estimates in this report are typically either Estimating Class 5 estimates order of magnitude, concept screening: -20% to +50%, or Estimating Class 4 estimates, study or feasibility: -15% to +30% depending on the level of definition of the generating plant. Estimating Class 5 estimates and Class 4 estimates are defined as follows:"

Table 8-1 Estimating Classes (source: AEMO, September 2018)

Estimating Class	**Primary Characteristic**	**Secondary Characteristic**		
	Maturity level of Project Definition Deliverables Expressed as a % of complete definition	End Usage Typical purpose of estimate	Methodology Typical estimating method	Expected Accuracy Range Typical variation is low and high ranges
Class 5	0 to 2	Concept Screening	Capacity factored, parametric models, judgement or analogy	L: -20% to -50% H: +30% to +100%
Class 4	1 to 15	Study of Feasibility	Equipment factored or parametric models	L: -15% to -30% H: +30% to +50%

8.1.3 BEIS, NOVEMBER 2016

BEIS, November 2016 notes that:

“It is important to note there is a large amount of uncertainty when estimating current and future costs of electricity generation. For example:

- uncertainty over costs will be greater for more immature technologies;
- variation in capital and operating costs across sites;
- uncertainty over the fuel and carbon price trajectory for relevant technologies, and
- differences and uncertainty overload factors and hurdle rates.

This report has attempted to capture some of the above uncertainty by portraying ranges and in the new sensitivity analysis section. However, not all sensitives and sources of uncertainty are captured.”

“While we consider that the ranges of levelized cost estimates presented in this report are robust for BEIS analysis, these estimates should also be used with a level of care given the above uncertainties and future considerations, listed below:

- The analysis by contractors was largely undertaken in 2015.
- While BEIS has used updated fossil fuel prices and carbon values in this report, fossil fuel prices and carbon values are subject to considerable uncertainty. Implications of different assumptions are illustrated in the sensitivity analysis contained in this report.
- The levelized costs presented in this report are based on load factor assumptions that generally reflect the maximum potential (net of availability) of a plant (except for OCGTs and reciprocating engines). Where flexible technologies such as CCGT and CCS plants operate at lower load factors, their levelized costs will be higher than those presented here.”

Future Cost Projects – “There is significant uncertainty about how the costs of technologies will evolve over time. In general, estimates of the capital and operating costs of different electricity generating technologies in the future are driven by expectations and assumptions of technology-specific learning rates and by global and UK deployment levels.”

Current Financing and Hurdle Rates – [The] “NERA report provided a suggested range of hurdle rates that BEIS could use for each technology for projects starting pre-development in 2015. NERA provided a range for hurdle rates rather than a point estimate to reflect the uncertainty arising from their analysis.”

Hurdle Rate Projections – “Reflecting the additional uncertainty in making projections of hurdle rates, NERA provided BEIS with three possible trajectories for hurdle rates out to 2030 based on different policy scenarios in the future. Both peer reviews highlighted the difficulty of accurately projecting hurdle rates out to 2030.”

High and Low Capital Costs (incl. Pre-development) – “It should also be noted that the ranges across different capital cost estimates for technologies have different interpretations between the renewable and non-renewable technologies. For renewables, there is considerable uncertainty over the actual supply curve range. For non-renewable technologies, the capital cost range represents uncertainty for any given project. It should also be noted that all the estimates for non-renewable technologies do not reflect site-specific considerations which may become apparent through a detailed cost discovery process.”

High and Low Fuel and Capital Costs – "For some technologies (e.g. CCGT, CCS, biomass and waste technologies), fuel costs are a major driver of the levelized cost. In order to demonstrate this, sensitivities which explore uncertainty over both fuel costs and capex costs are provided."

8.1.4 LEVEL OF UNCERTAINTY BY PLANT TYPE

Table 8 1 indicates the level of uncertainty around estimating future plant costs derived from the main factors discussed above. To simplify the analysis, the main sources of uncertainty affecting accurate estimation of future plant costs have been aggregated into three categories:

- Technological

  Technological sources of uncertainty in estimating future plant costs are derived mainly from the level of maturity of each generating plant type. For example, hydro generating technologies are considered mature and hence the possible effects on capital cost from technology advances for hydro plants will be minimal. Technology advances predominantly provide a negative pressure on plant capital costs.

- Materials

  Fluctuations in commodity and component prices such as steel, concrete, energy, labour and transport costs have an impact on the cost of key raw materials which form a large part of overall plant capital cost. As commodity and materials prices can and do move up and down, the impact on overall plant cost can either be positive or negative at any given time, however the overall trend is a positive one.

- Environmental, regulatory and financial

  This category includes such sources of uncertainty as a future price of carbon emissions, consenting costs, financing costs and political or regulatory support for the generating technology type. The sources of uncertainty in this category can either provide a positive or negative pressure on plant capital costs in New Zealand.

For each category of uncertainty and generic plant type, WSP has provided its view on the level to which future plant costs could be affected. These have been defined as:

- Low – The source of uncertainty has the potential to affect the estimation of future plant costs less than 10%;
- Medium – The source of uncertainty has the potential to affect the estimation of future plant costs within a range of 10-20%; and
- High – The source of uncertainty has the potential to affect the estimation of future plant costs by more than 20%.

For example, utility scale solar generating technologies are relatively new (compared to other forms of generation) and hence a significant amount of technological advancement is possible which may have a similar sized effect on reducing the overall plant cost (per MW) of a future project.

Table 8-2 - Uncertainty in future thermal generation plant costs

Sources of uncertainty and potential effects on future plant costs			
Plant type	Technological	Materials	Environmental, Regulatory and Financial
	Includes design innovation, efficiency improvements, learning effects and economies of scale.	*Factors include commodity prices, supplier competition and engineering costs.*	***Includes consenting costs, carbon price, interest rates and land costs.***
Thermal			
- CCGT	Low (-)	Medium (+/-)	Medium (+/-)
- Conv. ST	Low (-)	Medium (+/-)	Medium (+/-)
- OCGT	Low (-)	Medium (+/-)	Medium (+/-)
- Recip	Low (-)	Medium (+/-)	Medium (+/-)
- IGCC	High (-)	Medium (+/-)	Medium (+/-)
- ASC	Medium (-)	Medium (+/-)	Medium (+/-)

Note: The '+/–' symbols indicate the direction future plant costs may typically move, i.e. 'up', 'down' or 'up and down' in response to the source of uncertainty.

9 ABOUT THE AUTHORS

9.1 WSP PROJECT TEAM

WSP is one of the world's leading engineering professional services consulting firms. We are dedicated to our local communities and propelled by international brainpower. We are technical experts and strategic advisors including engineers, technicians, scientists, planners, surveyors, environmental specialists, as well as other design, program and construction management professionals. We design lasting Property & Buildings, Transportation & Infrastructure, Resources (including Mining and Industry), Water, Power and Environmental solutions, as well as provide project delivery and strategic consulting services. With 4,800 talented people in 62 offices across Australia and New Zealand, we engineer projects that will help societies grow for lifetimes to come.

Regardless of turbine configuration, WSP has a well-deserved reputation as a leader in thermal power generation technology across the Asia-Pacific region. We provide end-to-end services and advice to our clients to help them remain competitive in today's global power economy.

These services include asset maintenance and life extension work, as well conceptual design, project planning, detailed design and owner's engineer work.

WSP Project Team

Les Pepper, a project manager and asset management consultant with 40+ years in the New Zealand power sector. He worked a Huntly Power Station, from construction project days through to the development of the unit 5 CCGT plant. He has worked his way up from maintenance, projects, engineering services, through to management positions before progressing to energy/power consultancy roles. He has previously worked for the New Zealand Electricity Department (NZED), Electricity Corporation of New Zealand (ECNZ), Genesis Energy, Opus International Consultants Ltd and now with WSP NZ's Power team, based in Taupō.

Aylwin Sim, a management consultant with extensive experience delivering strategic advice and implementing management systems in the electricity industry. His advice comes from 16 years' experience working in asset-intensive industries across a range of corporate and government clients in New Zealand. Aylwin has experience in strategic asset management advisory, preparing asset management plans, conducting regulatory reviews and audits, implementing enterprise management systems, developing business cases and organisational design. He has worked on projects in the power, oil and gas, aviation, education and government sectors.

Nigel Matuschka, a Chartered Professional (CPEng) mechanical engineer with 20 years' experience. His energy industry experience includes working in power generation, mining & metals, oil & gas and petrochemical. He has carried out feasibility studies, FEED, consenting, process design, tender preparation, detailed mechanical design, pressure equipment designs and specifications, engineering and construction of power plants in NZ and internationally. These have included design and commissioning of power plants in the Philippines and Indonesia and on oil & gas rigs in the North Sea of the UK.

WSP core generation plant capabilities include:

Discipline	Plant	Activities
Mechanical	Combined-cycle and gas turbine (GT) plant	• GT remaining life assessment • Project management & supervision of major and minor overhauls • Equipment trend/sequence of events analysis • Writing O&M and LTSA Specifications • Evaluating O&M and LTSA offers • Review of spare parts holdings • Root Cause analysis of GT component failure • Technical assessment of vibration tests • Troubleshooting
	The steam turbo generator side:	• C&FH Plant, Condensers, Feedwater Heaters, Pumps, piping, controls and other auxiliary equipment • Cooling Systems including CT's, pumps, steam condenser, auxiliary cooling systems • Aspects of steam turbines and auxiliaries • Mechanical aspects of generators (including hydrogen cooled machines), and associated systems (gas supply, gas monitoring, gas cleaning).
	Aspects of boiler side including:	• Ash and ash/slurry disposal, materials handling systems, water and management (civil, hydrology, mech) • Equipment inspection during manufacturing and testing phases • Outage supervision, quality assurance and general site support
	Piping systems	• Thermal modelling (SteamPro, SteamMaster, Thermoflex, GTPro, PEACE, TOPS) • Failure investigation • Commissioning supervision and support
Electrical	All plant	• Electrical design • Arc flash studies • Load flow studies • Protection studies
Quality Services	All plant via WSP's UK Quality Services Department, managing quality assurance/surveillance programs at	• Boiler waterwall panels – China • Boiler tubes – China • Boiler reheater fabrication – China • Hydro turbine runners – Italy • Hydro turbine runners – Spain

	manufacturing facilities globally:	• Titanium Condenser Tubes – USA • On Line Tube Cleaning system – Germany • Boiler forgings – Korea • POM Power Station – Overseas inspections (various locations) • Guthega Generator Rewind – Overseas inspections • OCGT Generator rewinds – Switzerland • Transformer inspections – China • Site tube rolling procedure qualification – USA
Asset Management	All plant areas	• Asset management advisory services • Asset Management System improvement processes

10 DISCLAIMERS AND LIMITATIONS

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