FUTURE GEOTHERMAL GENERATION STACK

Factors influencing new geothermal projects in NZ to 2060

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ABSTRACT

This paper is based on a review that was commissioned by the Ministry for Business, Innovation and Employment (MBIE) in consultation with Transpower, with the objective of estimating the possible timing and cost of future geothermal projects in New Zealand over a 40-year horizon. Access to resources is likely to constrain the pace of development as well as project cost and electricity price. Regulatory and consenting difficulties may lead to delays for future projects. It is not expected that new technology will greatly reduce the cost of future geothermal generation nor significantly extend the geographical spread of its coverage to many lower-temperature resources. Thus, future large-scale development is likely to continue to be within the Taupō Volcanic Zone and at Ngāwhā in Northland.

Geothermal generation can run in a load-following manner, but the most economic use of geothermal generation will remain as base load because of the high fixed cost associated with the resource development. Previous studies in New Zealand have over-stated the greenhouse gas (GHG) emissions of existing and future geothermal plants. More specific figures are given based on actual recent data for developed fields, as well as revised estimates for greenfields. The present MW-weighted average emissions intensity for existing geothermal projects is 76 gCO_2eq/kWh (2018), which has been steadily declining (from 91g CO_2eq/kWh in 2015).

Greater future direct use of geothermal energy is generally expected to be complementary with rather than competitive to electricity generation or to be based on lower-temperature resources. Scaling factors based on enthalpy and project size have been applied to the power plant portion of the project cost. On this basis capital costs range from 4,734 to 9,767 NZD/kW with a weighted average of 5,782 NZD/kW.

The total estimated available future geothermal generation by 2060 is 1,035 MW. This total is slightly higher than previously presented (MBIE 2016), but it is likely that many projects will be commissioned later than previously assumed.

1. INTRODUCTION AND BACKGROUND

1.1 Background

This paper is based on a review that was commissioned by MBIE in consultation with Transpower (Lawless et al., 2020). The objective was to estimate the possible timing and cost of future geothermal projects in New Zealand over a 40-year horizon. Parallel reviews were carried out in other renewable energy sectors. All of the studies can be downloaded from the MBIE website.

Previous work for MBIE in 2016 gave a prediction of around 945 MWe of new geothermal projects. Many of the long-term New Zealand electricity modelling scenarios (e.g. Productivity Commission (2018), ICCC (2019), BEC2060 (2019), include much higher MWe of geothermal in their long-term (2050, 2060) scenarios, which to the present authors appear unrealistic.

The MBIE's previous Generation Stack models assumed the lowest long run marginal cost (LRMC) plants are built first, many of which are geothermal, but some of the fully consented plants (several now built or under construction) actually have higher LRMC than some of the other projects, still under consideration. It is therefore apparent that for geothermal plants in New Zealand LRMC is not the only criterion as to when projects actually get built.

1.2 Previous work on resource capacity

In a review of this type it is necessary to make estimates as to the capacity of undeveloped resources, in a way which can meaningfully be compared to existing and brownfield projects. There is no consensus as to how this should be done, and further work on this issue is clearly needed. For the present purposes the following sources of estimates were used in order of priority:

- Field-specific estimates, the most comprehensive of which are generally available through the resource consenting and monitoring process,
- Published estimates by the Bay of Plenty and Waikato Regional Council, the source of the latter being a publication by SKM/WRC (2002).
- Estimates for other fields published by Lawless (2005).

Reference should be made to the full MBIE paper for assumptions regarding estimates on individual resources.

It is important to distinguish between total resource capacity and project capacity. The above estimates referred to total resource capacity, that is to say what could be expected to be economically extracted while running the resource to depletion, albeit over a longer time scale than resource consents will be available for. In the scenarios considered here, what is estimated is what a prudent developer might be prepared to undertake within the next 40 years, having regard to resource uncertainty and the requirement for sustainable management under the Resource Management Act (RMA), which will generally require some of the resource to remain un-depleted. Thus, the projects included here in the 'future geothermal generation stack' are generally less than the ultimate resource capacity.

2. GREENHOUSE GAS EMISSIONS

Geothermal fluids and reservoir rocks vary considerably from field to field, as well as variations in power plant technology, efficiency, reinjection, management, etc. Hence greenhouse gas (GHG) emission intensity varies significantly, from 18-21 gCO_2eq/kWh for some Icelandic plants and Wairakei in New Zealand, to 1,640 gCO_2eq/kWh in Alasehir-Kavaklidere in Turkey (Layman, 2017). Bertani and Thain (2002) calculated a weighted world average of around 122 g CO_2eq/kWh.

Until recently, only limited geothermal field emissions data was publicly available in New Zealand. What was available, were aggregated data from MBIE on fugitive emissions from the geothermal power generation sector. This resulted in an estimated average of 115-130 g CO_2eq/kWh over recent years.

Recently, however, the NZ Geothermal Association managed to gather confidential company emissions data and publish almost 10 years' worth of geothermal emissions data (McLean and Richardson, 2019, Figure 1 at end of paper). Relevant conclusions from this review include:

- The MW-weighted average emissions intensity in 2018 was estimated at 76 gCO_2eq/kWh. This was down from 91 gCO_2eq/kWh in 2015.
- A large variation in emission intensities between fields: in 2018 from 21 gCO_2eq/kWh for Wairakei A&B to 341 gCO_2eq/kWh for Ohaaki;
- A general, long-term trend towards lower emission intensities for each individual field, as well as in the aggregate, weighted average.

3 METHODOLOGY ADOPTED FOR ESTIMATING CAPEX AND OPEX

3.1 CAPEX

Estimating costs for future geothermal investments faces many uncertainties and the variation in capital costs (CAPEX) can easily be as much as 20-30% depending on project specifics. CAPEX can also vary depending on the financial assumptions with regard to how sunk costs are treated. For example, some of the existing projects took over several highly productive historical wells drilled by the government decades before, but at significantly less than replacement cost. Given the very long history of some New Zealand projects before commercial operation the differences can be significant.

GT Management (2019) produced a detailed Production Cost Model, which incorporates a large number of factors to estimate geothermal CAPEX. That model has the advantage of having been based on extensive consultation with the international industry, and peer review by the World Bank. While that modelling was specific to Indonesia, and some of the specific costs and financial assumptions (e.g. cost of capital, internal rate of return, tax treatment) will differ from those in New Zealand, it included a number of useful empirical cost correlations which are used here.

As in many energy projects, there is a tension in geothermal projects between the desire by developers and regulators to proceed cautiously in a staged or modular fashion, and the fact that the cost of geothermal power projects has significant economies of scale. That applies particularly to the power plant cost: the number and cost of wells and SAGS (steamfield above ground system) tend to be more linearly dependent on the MW. The effect of size on power plant cost was quantified by GT Management (2019). That correlation was developed further with Indonesian cost data and extensive feedback from developers.

While the correlation is specific to Indonesia, it should also be applicable in New Zealand to a sufficient degree of accuracy for the purposes of this report. It has been used in developing the capital cost estimates, assuming that the power plant is roughly 40% of the total project cost.

Figure 2 shows three correlation ratios/formulas, in case multiple plants/units are ordered or built around the same time. For the present purpose, the single unit correlation is used unless stated otherwise. The authors have assumed that the remaining 60% CAPEX has a fixed cost per MWe, and that it scales linearly with MW capacity. Note that the data included in Figure 2 also incorporates a time-based escalation (of about 10%) from when the baseline 1 x 55 MW reference cost was initially established from market data.

Reservoir enthalpy and well productivity affect the plant design and number of wells, including the production-to-reinjection-well ratio, and complexity of the SAGS. For this purpose, a single reservoir enthalpy scaling factor was used as in Table 1.

A useful international CAPEX benchmark is 4,000 to 5,000 USD/kW for greenfield projects, with the higher number being more appropriate to small projects with low-quality resources. The 4,000 USD/kW figure is approximately 6,000 NZD/kW. There are however several reasons why CAPEX for recent projects in New Zealand may have been lower than the international benchmark:

- The mature and competitive nature of the New Zealand geothermal industry.
- Many of the projects in New Zealand were brownfield, rather than greenfield projects (e.g. Ngawha, Te Mihi);
- Even in projects which have not previously had power plants, the level of risk is lower than in most overseas projects because of the large legacy of resource data;
- In some cases, previously drilled wells would have been purchased at less than replacement cost, or taken into the project at a discounted sunk cost;
- Access and infrastructure costs are generally low in the TVZ;
- Drilling costs per metre in NZ are lower than in some countries and in some cases, wells are shallower;
- Some projects may have taken advantage of a higher NZ/US dollar exchange rate at the time.

The publicly available data from projects in the past decade bears this out: details are available in the full MBIE report.

Enthalpy (kJ/kg)	Multiplier on basic power plant costs	
760 – 940	1.3	
940 – 1450	1.0	
> 1450	0.9	

Table 1: Scale factors for enthalpy (GT Management, 2019)

3.2 OPEX

Operation and Maintenance costs/expenditures (OPEX) for geothermal power plant, as for solar and wind, are virtually all constant per MW installed capacity, rather than being variable on a per MWh delivered energy

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In this report all fixed O&M costs apart from make-up drilling are clustered together and summarized in one factor, starting with Contact Energy's recent Tauhara estimate (Contact, 2018) at NZ$ 20/ MWh (ex carbon cost), which results in NZ$ 157,680 per MW per annum (90% CF).

For individual projects, variations in resource run-down rate will play a role in terms of make-up drilling, which can also be treated as fixed O&M. The rate of decline of individual geothermal wells, and of geothermal resources as a whole, varies significantly. For the present study, the authors have used an estimate of 3% annual run down. This is at the lower end of the possible range, but consistent with the conservative approach taken to sustainability in New Zealand. For a 55MW project, with wells producing on average 9MW each, that would result in around one well every 5.5 years. At NZ$10M per well, that would cost NZ$1.8/annum or $33,000/MW/annum as fixed O&M. In this analysis those costs will be evenly spread per year, though in practice especially on larger projects they would be drilled in batches every few years to save on rig mobilisation costs.

Combining the above factors, the authors estimate fixed OPEX for all projects at NZ$190,000/MW p.a. (NZ$ 190/kW). Note that this figure includes all O&M costs, including replacement wells. For modelling purposes this is appropriate, although from a strict accounting perspective replacement wells are normally regarded as capital asset additions rather than being expensed.

3.3 Greenhouse gas emission costs

For this study, the authors have developed a semi-quantitative approach, using four emissions intensity categories to classify each project/field: from very low – low – medium – high, in gCO_2eq/MWh. No attempt was made at calculating the specific potential cost impact on LRMC for each project, as MBIE modelling with the produced 'future geothermal generation stack' is expected to calculate the GHG emission costs under various carbon market price scenarios, and incorporate these in LRMC-calculations accordingly. An average station, using a MW-weighted average of 75 gCO_2eq/MWh and a "NZU" carbon price of $25 per tonne would cost $15,600 per MWp.a.

4 POTENTIAL FUTURE DEVELOPMENTS

4.1. Potential for new technology to increase existing geothermal generation capacity

Geothermal generation is a mature technology with a history of over 100 years. Drilling for geothermal wells is very much an offshoot of the oil drilling industry, so radical changes in geothermal drilling technology are not expected, although there are some areas for further research and such work is continuing in the USA. Therefore, while there is some scope for technical improvements in geothermal generation projects, it can be expected that the gains will be small and incremental. More significantly, the rate of cost reduction for geothermal generation due to technical improvements is likely to be significantly less than for solar, and to a lesser extent wind. That will disadvantage geothermal generation relative to the other newer sources as time progresses.

There is some potential to take up existing technology which has not been widely used to date in New Zealand, but whether that happens will be driven by costs and the regulatory environment. Some possible changes in geothermal technology over the coming decades include:

- Greater use of digital technology to improve resource investigation, drilling, operations and maintenance. Geothermal operators are reporting small but steady improvements in this regard;
- Greater use of low-temperature binary plants. This is likely to be mainly restricted to retrofitting as bottoming plant utilising brine from existing condensing power schemes (with limited opportunities) rather than as stand-alone projects;
- Use of pumped wells in conjunction with binary plants on lower temperature resources. Similarly, for economic reasons, this is likely to be restricted to un-tapped areas of already developed resources rather than moving into wholly new areas;
- Carbon capture of carbon dioxide for industrial or agricultural use. This is already being done, for example for many years at Kizildere in Turkey. For most uses it requires removal of the hydrogen sulphide content of the total non-condensable gases (NCG), which is possible but at a cost. This may be forced on geothermal projects in the more distant future if carbon prices rise significantly. It has also been suggested that geothermal reservoirs could be used for carbon capture and storage (CCS) not only of their own emissions, but also of carbon dioxide emissions from other sources, possibly with (injected) carbon dioxide eventually replacing steam as the working fluid in geothermal power plants. Some theoretical modelling has been carried out on this concept showing that the thermodynamics are favourable, and some small-scale trials in Iceland, but the practical challenges are formidable, especially in terms of scaling and corrosion and guaranteeing the GHG remains underground;
- Improvements in controlling deposition of silica and other deleterious minerals in the waste stream. This is an area where there are new developments, with New Zealand taking a leading role. This includes the Geo40 process, which produces a commercial silica product and is being trialled in several areas including NZ and Japan. Apart from extracting minerals, it creates an opportunity to extract more energy from the brine fraction of geothermal fluid by allowing for a lower reinjection temperature. It is most applicable to high temperature resources, where it could make a modest contribution to the output of new plants. It also provides the opportunity to extract other minerals from the geothermal waste streams. For example, lithium is a valuable minor component of geothermal brine, but recovering it means either inhibiting the co-deposition of silica or removing the silica first. That could provide a valuable additional revenue streams for future geothermal projects as well as helping to meet sustainability criteria;
- Deeper drilling in known high temperature areas to tap super-critical fluid. This has been proposed in several countries including New Zealand as a means of sourcing geothermal fluids with much higher enthalpy, hence much greater well productivity, than in conventional projects. Some trials of this have been conducted in Iceland and Japan, with mixed results. There are significant practical difficulties, not only with the drilling and well design but also with

corrosion and mineral deposition by these fluids. Even if the practical difficulties can be solved this is considered by the present authors likely to be too expensive to be included in the Generation Stack over the time period considered;

- Creation of artificial geothermal resources by hydraulic stimulation in hot impermeable rocks at depth (Hot Dry Rock, HDR or EGS projects). This is superficially an attractive proposition, as hot rocks, especially granites, exist in many parts of the world, including New Zealand, outside of the naturally convective magmatic-related geothermal systems. Experimental schemes have been developed in several parts of the World including Europe and Australia. However, the flow rates achieved and the cost of drilling to such depths has meant that the economics of such schemes are unfavourable. It is very unlikely that such projects would become economically feasible in New Zealand within the time frame considered;
- Possible use of production from deep sedimentary systems. This is again a relatively new approach being considered in Australia and parts of Europe (especially where lower temperature fluids can be used directly for district heating) and its application to New Zealand will be limited;
- More economical methods of resource exploration, especially by the use of deep slimhole wells. This will have limited application in New Zealand, where most initial exploration drilling has already been undertaken;
- Expanded use of improved general drilling techniques, e.g. the use of aerated drilling to minimise down-hole problems, possibly the use of hammer rather than rotary drilling for certain types of formations, improved bit technology to allow holes to be drilled for longer without the need to trip-out-of-hole for bit changes. These can be expected to have some incremental cost advantages in New Zealand but a resulting radical drop in costs is not expected.

4.2. Potential for geothermal generation to be extended to areas outside the existing Rotorua-Taupo and Ngawha areas

High temperature geothermal resources in New Zealand are confined to the Taupo Volcanic Zone (TVZ) and a single occurrence at Ngawha in Northland. It is geologically improbable that any other undetected high temperature naturally convective resources exist at economically drillable depth in New Zealand. Hot dry rock projects are excluded for the reasons given under above. Therefore, any expansion of geothermal generation on a significant scale outside these regions will require the use of lower temperature resources, which inevitably means binary power plants and probably the use of pumped wells, as lower temperature wells cannot normally self-discharge by two-phase flashing.

Geothermal power projects of this type have been successfully developed in many countries. They *can* be economic provided some of the following special circumstances exist:

- Relatively high power prices e.g. Germany, where prices for electricity from renewable sources can be more than 5 times the average price in New Zealand.
- Extensive shallow geothermal reservoirs with high pressures/water levels. This is the case in parts of the USA and Turkey;
- High permeability near-surface geological formations such as terrestrial sediments, to provide an extensive reservoir for geothermal resources to accumulate;
- Extensive high permeability deep sedimentary reservoirs that have been explored by oil wells, preferably with numerous existing but abandoned wells that can be converted.

In the absence of such circumstances, such projects, while technically possible, will be sufficiently expensive that they are likely to be more expensive than other renewable sources especially wind and to a lesser extent solar. There are two situations where that may not apply:

- Energy recovery from hot water produced by oil wells. There are oil wells in Taranaki which produce water hot enough to generate electricity in a binary plant, albeit at significant cost because of the modest temperature. Those opportunities are sufficiently limited and small scale at present that they can be ignored for the present purposes. Reyes (2019) has observed that there are only four abandoned oil wells with temperatures over 150 °C in Taranaki, and these are scattered rather than grouped to provide a larger project. The potential is perhaps 5 MW in total, and it is unlikely that there will be a large expansion of the oil industry in the foreseeable future;
- Water at around 200 °C in the outflow zones of some TVZ high temperature geothermal systems, such as at Mokai. That has the advantages that the permeability is high in some of the near-surface pyroclastic formations, the outflows are shallow and represent a significant volume of resource, and in most cases the extent of the resource has been well defined by geophysics and previous drilling. These also have the advantage that, unlike the separated brine stream from high-temperature projects, the silica content of the water has re-equilibrated underground and so does not pose such a risk of deposition in the surface pipework as would the use of a bottoming plant on a high temperature resource. However, given that such occurrences are all in the TVZ, they can be regarded as "second tier" additions to known high temperature projects.

It is concluded therefore that the potential for projects outside the known high temperature areas in New Zealand is very limited.

4.3. Potential for geothermal to generate in a load-following manner, to compensate for intermittency of other electricity sources

Geothermal power plants, having high CAPEX and low OPEX, are usually operated in as close to base-load operation as possible. They achieve higher capacity factors than any other type of power plant, often over 95%.

From a technical perspective, it is possible to operate geothermal power plants in a load following manner. Generally, this is achieved as the load is reduced by diverting steam to a silenced atmospheric vent (usually a rock muffler) because the original steam source (the wells) cannot respond as quickly as conventional boilers. Steam venting can easily occur as quickly as the load change on the turbine. Obviously, the vented steam represents a loss of energy and hence a potentially significant decrease in overall thermal efficiency. The loss of steam can be minimised by partial throttling of one or more production wells, but fully 'shutting in' of individual wells is highly undesirable because of the potential for thermal cycling problems. Therefore, depending on the degree of load reduction, there may still be some residual steam venting.

Steam venting in this manner may be considered environmentally or socially problematic in some areas, especially if the project is located close to a population centre. It may also in New Zealand be regarded as "unsustainable" (not efficient use) under the RMA, although the amount of steam venting may actually be very small, especially if undertaken in support of predictable diurnal load variations. For binary plants using brine, load following is more easily achieved by simply bypassing the brine flow directly to injection. As this hotter brine is then being reintroduced into the sub-surface system there should be no issues regarding unsustainability.

One example is the Tongonan I power plant in the Philippines. It had a 3 x 37.5 MW condensing steam turbine configuration. The number of units was partially designed because spinning reserve was required for a nearby copper smelter. When it was built it was the only power source on the island of Leyte, so it had to operate in a completely load-following manner. It was a technical success (Minson et al, 1985). However, it would be unlikely to be acceptable in New Zealand because it achieved load shedding by discharging surplus steam to the atmosphere.

Closer to home, when first built what is now the Poihipi plant operated in a load/cost-following manner. The owner, Geotherm Energy, had a daily resource consent allocation which would not support the full output for 24 hours. Rather than run the station at part load (which would have been physically and economically inefficient), the station was run at the full 55MW output during the day, when spot power prices were highest, and then reduced to about 3 MW overnight. It was not shut down completely to avoid thermal cycling. This was also technically successful. However, the station is no longer run in that way as it is now inter-connected to the Te Mihi/Wairakei steam supply system which has much larger daily consents.

As these examples show, it is quite possible to run a geothermal power plant at variable load. It is however economically unattractive (except in the special case where it is consent limited and cost following), since the economics of geothermal power projects are normally designed around continuous operation. In effect the last few percent of operation represent the profit margin.

In general, the efficiency of geothermal plants drops off at part load, as with any thermal plant, so there is an incentive to maximise their output given that the limiting factor is usually consented fluid take, not MW. On a small scale, in recent years there has been a move to adapt resource consent wording to average fluid take over longer than a daily period to allow for some make-up of outages.

Summarizing the above, the authors see little potential for geothermal power plants in New Zealand, which will be mainly located near the central part of the grid system, to firm up the intermittency of other power plants and load to any large degree by being load-following. On the basis of scenarios presented in the report, if all of the new geothermal generation postulated here was in fact developed over the next 40 years, it would be more than sufficient to provide baseload to replace all remaining thermal plant, because of the high capacity factors of the geothermal plant.

4.4. Extent to which non-electric uses of geothermal energy will compete with, or complement generation

In most cases geothermal direct use will be complementary to electricity generation and can provide a valuable additional revenue stream. Many direct uses require lower temperature heat than is suitable for regular condensing steam geothermal turbines, so cascaded uses are common, as in the case of the Prawn Farm at Wairakei, which heats river water to around 25-30°C using geothermal brine from the Wairakei power plant discharges.

Generally speaking, large geothermal power schemes produce a vast surplus of low-grade heat which can be readily utilised provided silica deposition and fluid disposal issues can be overcome. In some cases, it may be possible to make use of individual high temperature wells which are either marginal for production for power generation or in an inconvenient location to connect. Although from a technical perspective direct use of geothermal heat may be more efficient than conversion to electricity, the economic value of electricity is generally greater than that of the equivalent amount of heat. One of the biggest hurdles to overcome is obtaining a load of sufficient size to justify well drilling. As a stand-alone proposition there are very few industrial operations with enough scale to make it worthwhile, which is why these operations stand alongside electricity generation. Furthermore, in many cases the availability or cost of transport of raw materials to the geothermal site makes stand-alone direct use less attractive than generation. There are some exceptions to these generalisations, as follows:

- The very large dedicated industrial site at Kawerau uses a portion of the high-temperature resource for industrial direct heat use and will undoubtedly continue to do so;
- It is possible that re-powering the existing dairy factory at Reporoa which uses natural gas may take precedence over generation, though a complementary scheme is more likely;
- In some cases, such as Rotorua, preservation of the thermal activity for tourism logically takes precedence over power generation. This can also be considered a non-extractive "use".

5. DISCUSSION AND CONCLUSIONS

The pace of geothermal development in New Zealand has been modest over the past five years, after a period of rapid growth in response to declining gas reserves. The recent slow-down is mainly due to a flat power demand and the possible contribution to the grid of the Manapouri power scheme when the Tiwai Point aluminium smelter closes.

There is now a more positive mood in the industry following the government setting objectives for greatly reduced GHG emissions by 2050, though the recently announced Tiwai smelter closure will undoubtedly affect that. The generators have pointed out (e.g. keynote addresses at the 2019 NZGW) that there is limited scope for further de-carbonisation of the existing electricity grid because of our already-large degree of renewables generation and the practical advantages of maintaining some gas generation for load trimming. There are however significant opportunities for renewable electricity to substitute for other existing fossil-fuel usage in the transport and industrial sectors, which in 2019 made up 18% and 11% of our total emissions respectively. Direct use of geothermal heat can also make a significant contribution to reducing fossil fuel use, though that was not the subject of the study. The industry foresees on-going growth in the geothermal generation sector, albeit at a modest pace.

Access to resources through regulatory and environmental issues is more likely to constrain the pace of development than just project cost and electricity price. Over a third of New Zealand's high-temperature geothermal resources are currently fully or partially protected.

These uncertainties, and a comparison with the possible total economically developable quantity under a much more permissive regulatory regime, are further quantified in Figure 3 below. The possible tranches of MW used to build up this figure are as follow:

1. Already installed capacity: 1028 MW.
2. Already consented additions as in Table 2 (Tauhara, Ngawha 3 & 4): 300 MW.
3. Possible additions as in Table 2 that would require consents, but are within development fields (Ngawha 5 & 6, Mangakino, Mokai 4, Ngatamariki 2, Rotokawa 3 & 4, Kawerau 2, Rotoma, Tauhara 3, Horohoro, Rotokawa 4): 360 MW.
4. Possible additions as in Table 2 within research or limited development fields, that would therefor require a change of status (Tokaanu, Tikitere, Taheke, Reporoa, Atiamuri): 375 MW.
5. Other fields that are currently classified as protected, and so cannot be developed under the current regulatory regime. Note that the present authors do not advocate a change of the status of these fields, but have included them for the sake of completeness. Field capacities are taken from the estimates quoted above, where necessary converting to a 50-year project life (Ketetahi, Orakeikorako, Te Kopia, Waikite, Waimangu, Waiotapu): 556 MW. Not included in this are fields on offshore islands (e.g. White Island), the field under Lake Taupo, and Rotorua, at all of which development of power generation is considered impractical.

Based on the above, a significant proportion of future development is anticipated to be brownfield rather than greenfield. Regulatory and consenting difficulties may lead to delays for future projects. For the present purposes, it has been assumed that the current regulatory regime will remain more or less as is, but it is conceivable that more permissive or more restrictive approaches are possible in the future especially as a review of the RMA has recently been announced by the current government. The current draft National Policy Statement on Biodiversity (MBIE 2019), is an example of regulation that in its initial draft form could limit future geothermal development if that is not taken into account. It should not be assumed that all existing projects will automatically be re-consented, and the consents for all existing projects expire within the 40-year horizon. A more enabling regime and policy at the national level would accelerate the pace of geothermal development, but would also presumably make it easier to consent new wind, solar and hydro projects so would not necessarily favour geothermal relative to other renewable sources.

It is not expected that new technology will greatly reduce the cost of future geothermal generation nor, within what is likely to be economic in New Zealand, significantly extend the geographical spread of its coverage to much lower-temperature resources. Thus, future large-scale development is likely to only be within the Taupo Volcanic Zone and at Ngawha in Northland. Some modest cost reductions and gains in efficiency can be expected within the existing project areas, but to a lesser extent than the less mature renewable industries such as solar, wind and storage. Therefore, as time goes on there is likely to be a cross-over between the cost for new geothermal plant and other renewables.

There is scope for new geothermal plant to replace existing thermal plant, whether that be in a baseload or load following mode. From a technical perspective, geothermal generation can be made to run in a load-following manner, but the most economic use of geothermal generation will remain as base load, and since it is not anticipated that geothermal generation will extend to new geographical areas or remote parts of the grid, the scope for this to occur is limited, except possibly at Ngawha. It is conceivable that government initiatives to minimise carbon emissions might lead to geothermal becoming more important for load following, although the generators concerned would probably insist on a take-or-pay or capacity charge type of compensation to take account of the very high proportion of fixed costs of geothermal project operation.

Geothermal power projects do emit GHG, albeit in most cases at significantly lower rates per MWh than fossil fuel plants. Previous studies in New Zealand have over-stated the emissions of existing and future geothermal plants. More specific figures have been presented here for each prospect to a semi-quantitative level, based on actual recent data. The present weighted average emissions intensity for existing geothermal projects is 76 gCO_2eq/kWh (2018), which has been steadily declining (from 91 gCO_2eq/kWh in 2015) and is expected to continue to do so in the future. If much higher carbon prices eventuate in the future, the pressure on geothermal plants will increase and the expected emissions intensity would likely drop faster. In general, that would disadvantage new, higher emitting geothermal projects relative to other renewables (but much less than fossil-fuelled plants). The CCS technology does exist for removal of GHG from geothermal plants and reinjection in nearby reservoirs, and likely at a lower cost than for fossil fuel projects.

Greater future direct use of geothermal energy is generally expected to be complementary with rather than competitive to electricity generation or be based on lower-temperature resources. A notable exception to that could be at Kawerau where there is scope for expansion but the balance between future industrial use and electricity generation is unclear. Another possible future "direct use" is mineral recovery provided certain technical challenges can be overcome. Preservation of geothermal activity for tourism is a form of "direct use" which precludes generation at Rotorua and some of the protected systems in particular.

Taking likely earliest dates of COD into account yields an estimated sequence of future geothermal projects is summarised in Table 2. The total estimated available future geothermal generation stack by 2060 is 1,035 MW. Capital costs range from $4,734 to $9,767/kW with a weighted average of $5,782/kW (2019 New Zealand dollars). It is expected that at least 50% of the project capital costs will be in New Zealand currency.

This total new geothermal generation stack is slightly higher than previously presented by MBIE (2016), but it is likely that many projects will be commissioned later than previously assumed.

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Project	Location	Status	Enthalpy	MW	Capital cost NZD/kW	Capital cost NZ$M	Earliest date	GHG emissions category	Variable O&M, $/MWh	Fixed O&M, $/kW
Ngawha-3	Northland	Consented	Low	25	NZD 7,802	195	2021	High	0	190
Tauhara-2a	Waikato	Consented	Medium	125	NZD 4,734	592	2021	Low	0	190
Tauhara-2b	Waikato	Consented	Medium	125	NZD 4,734	592	2026	Low	0	190
Ngawha-4	Northland	Consented	Low	25	NZD 7,802	195	2031	High	0	190
Mangakino	Waikato	Generic-Greenfield	Medium	25	NZD 6,127	153	2030	Low	0	190
Mokai-4	Waikato	Generic-brownfield	Low	25	NZD 7,802	195	2030	Low	0	190
Ngatamariki-2	Waikato	Generic-brownfield	Medium	50	NZD 5,568	278	2030	Low	0	190
Rotokawa-3	Waikato	Generic-brownfield	Medium	50	NZD 5,568	278	2030	Low	0	190
Kawerau-2	Bay of Plenty	Generic-with-restrictions	Medium	50	NZD 5,568	278	2030	Medium	0	190
Rotoma-1	Bay of Plenty	Generic-Greenfield	Low	25	NZD 7,802	195	2030	Medium	0	190
Tokaanu-1	Waikato	Generic-with-restrictions	Medium	20	NZD 6,335	127	2030	Medium	0	190
Tikitere-1	Bay of Plenty	Generic-with-restrictions	High	50	NZD 5,023	251	2030	Medium	0	190
Taheke-1	Bay of Plenty	Generic-with-restrictions	Medium	25	NZD 6,127	153	2030	Medium	0	190
Reporoa-1	Waikato	Generic-with-restrictions	Medium	25	NZD 6,127	153	2030	Medium	0	190
Tauhara-3	Waikato	Generic-brownfield	Medium	30	NZD 5,968	179	2035	Low	0	190
Horohoro	Waikato	Generic-Greenfield	Low	5	NZD 9,767	49	2040	Medium	0	190
Atiamuri	Waikato	Generic-with-restrictions	Low	5	NZD 9,767	49	2040	Medium	0	190
Rotokawa-4	Waikato	Generic-brownfield	Medium	50	NZD 5,568	278	2040	Low	0	190
Tokaanu-2	Waikato	restrictions	Medium	100	NZD 5,119	512	2040	Medium	0	190
Tikitere-2	Bay of Plenty	restrictions	Medium	50	NZD 5,568	278	2040	Medium	0	190
Taheke-2	Bay of Plenty	Generic-with-restrictions	Medium	25	NZD 6,127	153	2040	Medium	0	190
Reporoa-2	Waikato	Generic-with-restrictions	Medium	25	NZD 6,127	153	2040	Medium	0	190
Ngawha-5	Northland	Generic-brownfield	Low	25	NZD 7,802	195	2041	High	0	190
Taheke-3	Bay of Plenty	Generic-with-restrictions	Medium	25	NZD 6,127	153	2050	Medium	0	190
Reporoa-3	Waikato	Generic-with-restrictions	Medium	25	NZD 6,127	153	2050	Medium	0	190
Ngawha-6	Northland	Generic-brownfield	Low	25	NZD 7,802	195	2051	High	0	190

Table 2: Summary: Future geothermal generation stack (figures in 2019-NZD)

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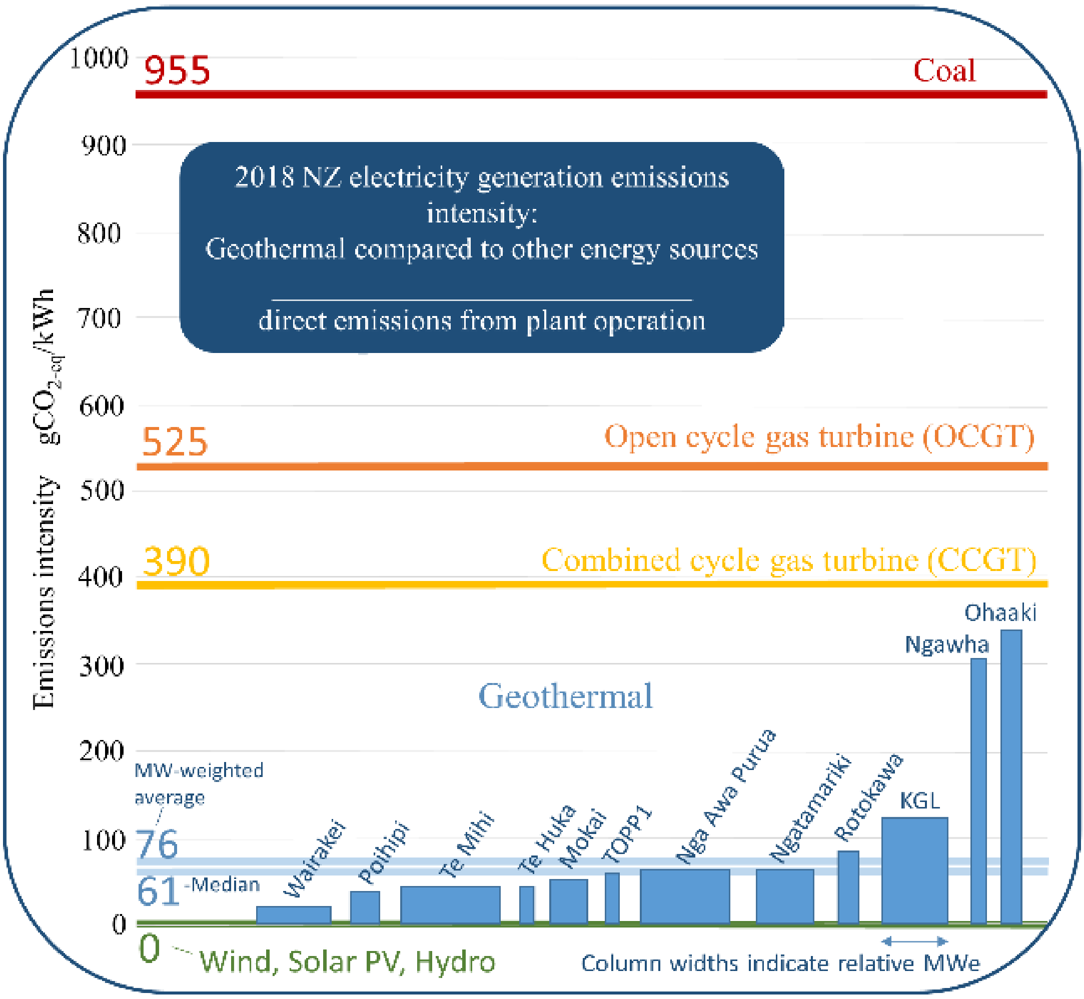

Figure 1: Comparison of the operational emissions intensity of geothermal power stations in New Zealand to other types of electricity generation (source: McLean and Richardson 2019)

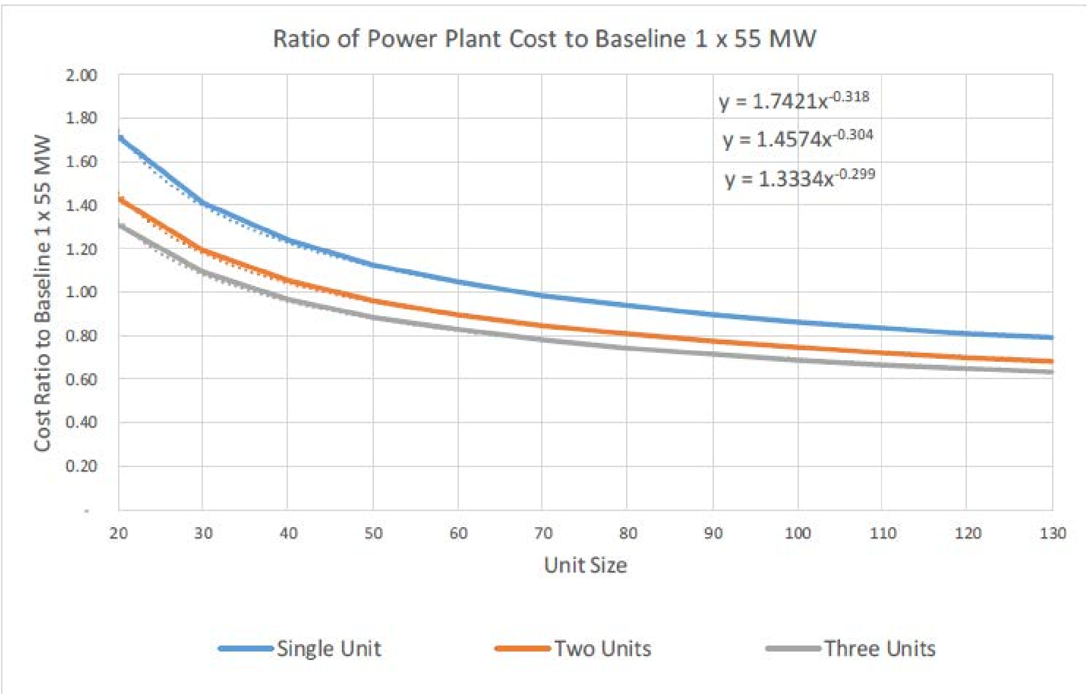

Figure 2: Variation of power plant cost with size (GT Management, 2019)

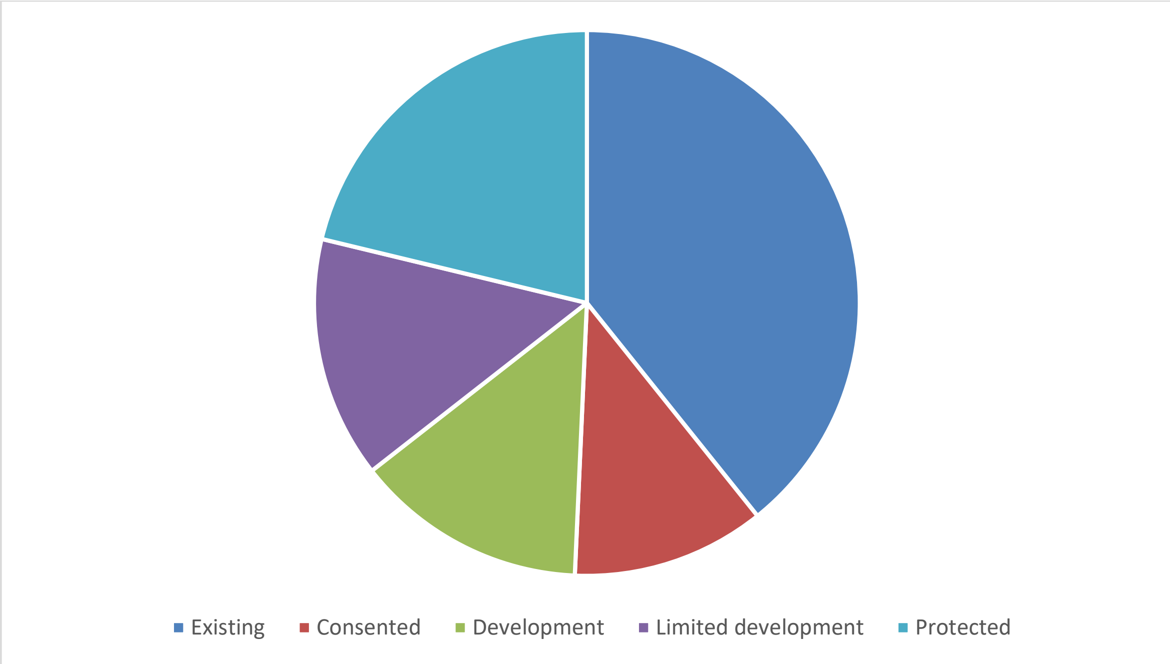

Figure 3: Distribution of status of existing and projected future generation and protected resources.