SINCLAIR KNIGHT MERZ

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Assessment of Current Costs of Geothermal Power Generation in New Zealand (2007 Basis)

- FINAL ISSUE
- October 2009

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Sinclair Knight Merz
25 Teed Street
PO Box 9806
Newmarket, Auckland New Zealand
Tel: +64 9 913 8900
Fax: +64 9 913 8901
Web: www.skmconsulting.com

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1. Executive Summary

This report develops a band, or envelope, of estimated specific capital costs[1] and electricity tariffs for geothermal resources in a New Zealand setting from analysis of 32 assumed geothermal development scenarios which comprise:

- a range of resource temperatures from 300 (high) down to 230 ^{o}C (low)
- two bands of well flow rates – a high rate of 150 $kg.s^{-1}$ and a low rate of 50 $kg.s^{-1}$
- four power cycle technologies – single and double flash condensing steam Rankine cycle plant, stand-alone organic Rankine cycle (ORC) plant and hybrid steam + binary plant, and
- two power plant capacities – 20 MW[2] and 50 MW.

The results are presented as:

1) gross thermal performance (thermal energy delivered divided by electrical energy produced)
2) plant specific capital cost (the capital cost divided by the gross plant capacity), and
3) the 'real' levelised electricity tariff[3] required to achieve a specified after tax internal rate of return, with certain assumptions made in regard to taxation and inflation. It is equal to the present (discounted) value of the before tax income stream divided by the present (discounted) value of the generation stream.

Gross thermal performance

High temperature[4]:

ORC < Single Flash < Hybrid < Double flash

Low temperature:

Single Flash < Double Flash < ORC < Hybrid

Financial performance

<u>Low Temperature (20 MW)</u>

Specific capital cost:

Single flash < Double flash = Hybrid < ORC

Electricity tariff[5]:

Single flash < Double flash < Hybrid < ORC [Range 10-14.5 NZc/kWh[6] real]

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[1] All costs in this report are presented on a 2007 cost basis.

[2] Unless otherwise stated, all capacities in kW or MW in this study refer to kW or MW electrical, gross at generator terminals, before deduction of in-plant electricity consumption.

[3] The 'real' (un-inflated) value is presented in this summary and is equal to the Year 0 electricity tariff. It is unaffected by the discount factor used, but it is dependent on the target internal rate of return (in this case 10%.

[4] In this context '<' means 'uses more thermal energy per unit of gross electricity produced than'.

[5] Based on 100% equity, 30% corporate tax rate, 8% straight line depreciation, 10% real after-tax internal rate of return, zero inflation.

<u>High Temperature (50 MW)</u>

Specific capital cost:

Single flash < Double flash = Hybrid < ORC

Electricity tariff:

Single flash < Double flash = Hybrid < ORC [Range 7-11 NZc/kWh real]

The ranking of the power cycle options in terms of thermal performance (gross) is quite different to the ranking in terms of financial performance. The advantage enjoyed by the binary plant options in terms of thermal performance at low temperature is not able to be translated into a financial advantage. There are two reasons for this, the first being that the binary plant options have somewhat higher plant parasitic loads which decrease their net thermal performance and thus their respective revenue streams, and although they have similar specific steam consumptions to double flash at low temperature (based on the cost assumptions made in the study), this is not enough to give them a levelised tariff advantage.

Nevertheless, the range is quite close and innovative approaches to equipment marketing and financing may be enough to tip the balance in favour of one technology over the other, as can be witnessed by the market success of ORC and hybrid plants in New Zealand over the past 15 years.

Double flash plants have higher specific capital costs than the single flash steam or hybrid plant options, in spite of double flash plant having good thermal efficiency at all of the reservoir temperatures examined. This is due to the greater complexity and thus cost required within the steamfield and power plant to accommodate the second stage steam flash separators and piping / instrumentation and the additional cost for fitting out a turbine with two steam inlets. It is these additional costs which penalise the double flash option relative to the single flash and hybrid options.

The analysis undertaken here for the double flash option is relatively conservative. A more aggressive approach could be taken through reducing the second stage flash pressure further to generate a greater steam flow from the second stage flash step. This would improve the cost performance of this option, however, this would be at the risk of silica super saturation in the waste brine exceeding 130% with increased potential for scale deposition even with chemical treatment.

The key output from the model runs are estimates of the ‘real’ electricity tariff required for each project development option for a variety of financial assumptions of which corporate tax rate, depreciation, inflation and equity content are the most important. These tariff values are equivalent

[6] In this study, kWh means kWh net, delivered at the grid connection point (assumed to be the high voltage side of the power plant step-up transformer, located at the power plant).

to the year 0 electricity tariffs required to achieve the financial hurdle After Tax Internal Rate of Return (IRR) assumed in the model. That is the rate which sets the free cash flow NPV to zero at the required post tax nominal discount rate.

The costs developed here are in New Zealand dollars. They are based on 2007 values, and were internally calibrated against costs being incurred for New Zealand geothermal developments, of which there were a number in progress at that time, and several overseas geothermal projects which were also in progress at that time.

This study did not look at greenfield developments greater than 50 MW. The main reason is that a greenfield developer would most likely not be able to attract the funds required for a larger development until some experience with the particular resource was gathered and the risks associated with a larger development were able to be well quantified. Furthermore a greenfield development of over 50 MW may struggle to obtain resource consents in New Zealand, given the conservatism of regulatory authorities and their preference for staged developments, for the same reasons.

This contrasts with the current situation in New Zealand where large second stage developments of medium to high temperature resources are occurring at brownfield sites (100 MW at Kawerau and 132 MW at Nga Awa Purua (Rotokawa)). This implies that the anticipated returns on these investments within the current electricity market in New Zealand are attractive – and developers are on record as stating that "Geothermal is the lowest cost source of new generation for New Zealand"[7].

For several years prior to 2007, geothermal development costs rose steadily in line with global market commodity and equipment price rises. These rises continued until the middle of 2008 when the current global financial crisis occurred and commodity prices fell back to 2003 levels. It is not certain that there is enough market data available yet to determine what is currently happening to geothermal power plant, steamfield and well costs to be able to compare current (2009) costs with the 2007 estimates used in this study. Nevertheless, when the situation becomes clearer it would be useful to update this report to a current (2009) basis, and to include brownfield cases in the range 50 – 100 MW.

[7] Baldwin, D. (2008). Chief Executive's Review. http://www.contactenergy.co.nz/web/pdf/financial/ar_20080923_chairman_ceo_review.pdf.

2. Introduction

SKM was commissioned in 2006 by the New Zealand Geothermal Association to prepare a report on the cost of geothermal power generation in New Zealand, this being task 7 in the NZGA's Action Plan (see http://www.nzgeothermal.org.nz/publications/Reports/NZGAAction Plan2006.pdf).

The NZGA Terms of Reference required that the report cover the following:

- provision of a band, or envelope, of unit costs for a number of development scenarios.
- clearly separate out offshore from local costs
- give a view on the currency that the offshore costs should be indexed to, and
- give a view on factors that have recently changed New Zealand geothermal generation costs and possible trends.

The Terms of Reference also require SKM to consult with the NZGA Board members and the Executive Officer on the following during the course of the study:

- Programme
- Drilling/well costs
- Well performance
- Capital costs
- Operating and maintenance costs
- A view on well replacement rate, and
- Cash flow during construction.

For various reasons this report did not get completed at the end of 2007, at which time the main author, Peter Barnett, moved from SKM to Hot Rock Limited. Paul Quinlivan picked up the authorship of the report in mid-2008, but final issue was delayed mainly due to the effort required to analyse the financial performance of the 32 options under study. For the past 2.5 years it has effectively been a labour of love, firstly by Peter Barnett (who wrote the majority of the text) and subsequently by Paul Quinlivan (who completed the financial modelling, wrote the financial section and updated the report text to reflect the report's status as of October 2009).

3. Components of a Geothermal Development

The key components of a geothermal power project (GPP) are:

- the geothermal field or resource and the wells that tap it;
- the fluid collection and disposal system that take geothermal fluids from the wells, conditions them, delivers them to the power plant, and takes the waste fluids for disposal;
- the power plant (within the power plant fence); and
- the electricity transmission system (to deliver power to the interconnection point).

The capital cost of a GPP is affected by factors such as the size of the project, the energy conversion process used, the size and number of individual generating units, and the character of the geothermal field (Mills, 2002). Since, to a significant extent, the character of the field affects the size and type of power plant, the capital cost of a GPP is greatly affected by the resource conditions. However, there is latitude for choice irrespective of the resource conditions, and these are matters for the developer to decide.

The electricity tariff dictates the range of generation technologies which it is feasible to apply. For example, elsewhere in the world the use of lower temperature resources and pumped wells is the norm, but at current and reasonably foreseeable prices in New Zealand this is probably not competitive in the medium term and has not been considered as an option.

Geothermal development costs are conventionally assessed on a greenfield basis – i.e. they take into account all costs incurred from initial surface exploration, exploration and development drilling, through to steamfield and power plant development, construction and commissioning. The New Zealand geothermal industry is somewhat unusual in that the Crown (the Government) has had an extensive historical involvement in resource exploration and proving and this has served to reduce development costs in New Zealand relative to true greenfield developments elsewhere. All of the recent geothermal developments in New Zealand have, to at least some extent, availed of this Crown legacy - Mokai, Poihipi, Rotokawa and Ngawha and the current development at Kawerau. Additionally, there are still unused productive Crown wells at Ngawha, Ngatamariki, Rotokawa and Tauhara.

3.1 The Geothermal Resource

The character of a geothermal resource / field is dictated by the following fundamental factors:

a) the area of the field (km^2)

b) the degree of recharge

c) the power potential of the field (MW) (i.e. energy reserves or field capacity)

d) the typical (e.g. average) flow of individual wells (in $kg.s^{-1}$ or $t.h^{-1}$)

e) the energy content of the fluids (in $kJ.kg^{-1}$ or $MJ.t^{-1}$), and

f) the chemical nature of the fluids (which includes non condensable gases, silica content, scaling and corroding potential, and toxicity).

Derived factors that result from these are as follow:

g) the field power density (derived from (a) and (b)) ($MW.km^{-2}$)

h) well productivity (derived from (c) and (d), with a conversion efficiency) ($MW.well^{-1}$), and

i) well density or well spacing (from (g) and (h)) ($wells.km^{-2}$ or km between wells).

To some extent, and understandably, geothermal resources in New Zealand so far have been "high graded" with the best prospects and the best sectors of those having been partially developed already. Future developments (other than expansions on existing developed fields or of the Ngatamariki field) may have to rely on less easily accessible or less desirable resource characteristics.

Considering each of the power project components, Table 3.1 below details some of the obvious impacts of the resource factors.

Field capacity sets the upper limit for plant size, but this may be more limited by resource allocation. Three out of the five resource consents issued for new developments in New Zealand (as opposed to re-consenting) in the past decade have been for much smaller quantities than were applied for, because of long term sustainability or environmental considerations rather than physical field capacity as such. A developer may choose to develop a smaller plant, because of capital limitations, but would ideally want to develop the largest possible plant.

3.2 Geothermal Steamfield

A typical approach for a geothermal steamfield development involves individual wells supplying one or more central separator stations via two phase pipelines. From the separator stations steam is piped to the power plant, and waste brine from the separators, and steam condensate from the power plant, is piped to reinjection wells. In this study pumped reinjection of waste geothermal fluids is assumed in all development options, and the cost of reinjection pumps and driving motors has been included. In practice depending on the topography and separator pressures it may be possible in some cases to avoid reinjection pumping.

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▪ Table 3-1 Impact of Resource Characteristics on Geothermal Development

Component	Resource Condition	Impact or Consequence
Resource / Wells	Field Area (km^2)	Sets upper limit on field size
	Field Capacity (MW)	Sets upper limit on plant size
	Well Productivity ($MW.well^{-1}$)	Directly affects number of wells required, thus wells cost
	Depth to Productive Reservoir	Secondary effect on drilling costs
	Well Density ($wells.km^{-2}$)	Secondary effect on drilling costs
	NCGs	None
	Temperature, Enthalpy, Silica Content	Secondary effect due to steam fraction, thus steam flow
	Calcite Scaling	Affects well productivity and requires costly work-overs, or requires dosing of costly antiscalant
Steamfield fluid collection and disposal system (= "FCDS", "SAGS" etc)	Field Area (km^2)	Refer to Resource/Wells above
	Field Capacity (MW)	Refer to Resource/Wells above
	Well Productivity ($MW.well^{-1}$)	Affects pipeline sizes (at individual well level), thus FCDS economy
	Well Density ($wells.km^{-2}$)	Affects length of pipelines, thus cost
	NCGs	None
	Temperature, Enthalpy, Silica	May affect selection of steam pressure
	Calcite Scaling	Will have little effect on FCDS
	Field Area (km^2)	Refer to Resource/Wells above
Power Plant	Field Area (km^2)	None
	Field Capacity (MW)	Sets upper limit on plant size, hence cost
	Well Productivity ($MW.well^{-1}$)	None
	Well Density ($wells.km^{-2}$)	None
	NCGs	May affect cost of plant, steam demand, and internal power load
	Temperature, Enthalpy, Silica Content	May affect selection of steam pressure, hence steam available from wells
	Calcite Scaling	None
	Field Area (km^2)	None
Electricity Transmission	Field Area (km^2)	None
	Field Capacity (MW)	May affect line rating, hence cost
	Well Productivity ($MW.well^{-1}$)	None
	Well Density ($wells.km^{-2}$)	None
	NCGs	None
	Silica Content	None
	Calcite Scaling	None
after Mills (2002)	Field Area (km^2)	None

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3.3 Geothermal Power Plant

There are several different types of power cycle that can be used for generation of power from geothermal energy. Those applicable to the New Zealand market include:

- Single flash steam Rankine cycle direct contact condensing plant
- Double flash steam Rankine cycle direct contact condensing plant
- Organic Rankine cycle (ORC) and Kalina binary power plant, and
- Hybrid steam-binary cycle plant.

Refer to Appendix B for the basic principles of the various power generation cycles.

Each of these cycle types has different applications depending on geothermal fluid temperature, NCG content, enthalpy and supply pressure and quite widely differing thermal performance and specific capital costs. Broadly speaking, these cycle types fall into two categories; one where the geothermal resource fluids are used as the process fluid, and the other where a secondary fluid, such as a relatively low boiling point hydrocarbon such as C_4H_{10} or C_5H_{12} (as used in ORC plant) or an ammonia-water mixture (as used in Kalina plant), is used as the working fluid and is separated from the geothermal resource fluids.

3.3.1 Steam Rankine Cycle

Steam Rankine cycles utilise pressurised steam directly to drive a turbine (and generator), with the steam either being exhausted directly to atmosphere in the case of back pressure turbines or into a condenser operating at high vacuum (typically 0.1 bara[8]) in the case of condensing steam turbines. In order to reject the energy of steam condensation, condensing steam turbines require substantial balance of plant and equipment such as condenser, hotwell pumps, cooling tower, and non-condensable gas removal system, which adds to the capital cost, but condensing turbine units produce about twice the power output for any given steam flow compared to back pressure units (steam turbines exhausting to pressures above atmospheric pressure).

Since there is usually a substantial fixed cost for drilling wells and for providing the fluid handling (steamfield) system, the portion of the required electricity tariff arising from wells and steamfield is considerably less for a condensing plant when compared to a back pressure plant.

Back pressure units at overseas projects are most often used on high temperature resources at an early stage in a development as a temporary measure to gain early reservoir production data and /or generate cash flow, where there is very strong pressure to cut capital costs (and where wells may

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[8] bara = bar absolute (1 bar = 0.1 megaPascal)

already exist as a sunk cost), or where there is limited power demand on a remote site. They may also be integrated into more complex developments for a range of reasons as at Wairakei and the Norske Skog Tasman development at Kawerau where there a process use for the low pressure steam. In this study, it is assumed that the steam turbine cycle for new projects would be of the condensing type.

3.3.2 Secondary fluids

ORC energy conversion technologies using a secondary working fluid heated indirectly by the geothermal energy include the Organic Rankine Cycle (ORC) and one of the Kalina Cycles. ORC power plants utilizing hydrocarbons have become commonplace in the New Zealand geothermal industry over the past two decades[9] with several recent developments utilizing such plant manufactured and installed by Ormat Industries. There is a worldwide installed capacity of ORC plant with a capacity in excess of 1000 MW, mostly manufactured and supplied by Ormat Industries. The standard designs for these plants are air-cooled although recently other water cooling options are also being used[10].

Kalina cycle power plants are binary cycle power plants utilizing ammonia-water mixtures. This cycle is a recent entry to the geothermal (or any) industry and operating experience in a geothermal environment is limited. At the present time, there are no large Kalina cycle units in geothermal service (the largest is currently a 2 MW plant at Husavik, Iceland, and the 3.4 MW Unterhaching plant in Germany commissioned in 2007 and then re-commissioned in mid 2009 after a number of early operational problems). Siemens commercial power plants based on the Kalina cycle have been available for several years to the New Zealand market through Geodynamics Power Systems, the Australasian sole agent for Kalina technology, however, no geothermal power developments have yet been undertaken in New Zealand based on this cycle and it has not yet been demonstrated that they offer specific cost advantages over ORC plants in the same temperature range so they are not considered further in this study.

For high temperature resources a combination (hybrid) cycle using back-pressure steam turbine and steam-powered ORC units, with or without further ORC units supplied with hot brine, can be utilised to provide similar overall thermal performance to a condensing steam turbine generator unit. The hybrid units supplied by Ormat are marketed as GCCU's - geothermal combined cycle units.

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[9] The first geothermal ORC power plant in New Zeland comprisd two 1.3 MW air cooled modular binary OEC units, supplied by Ormat to Bay of Plenty Electricity (BOPE) at Kawerau in 1989.

[10] The Fang plant in Thailand is an example of a water-cooled ORC power plant, as are those at Heber and Ormesa in the Imperial Valley in Southern California and the recently constructed Blue Mountain, Nevada and Thermo, Utah low-temperature geothermal power plants.

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Condensing steam turbine cycles, or hybrid combinations of steam turbine and binary units, are best-suited to high temperature geothermal resources. ORC units utilise the energy of both the steam and brine components of the total well fluid, and a significant portion of the heat supplied by the geothermal energy may be from the brine. The ORC may be better suited to medium temperature resources (< 240 ^{o}C), but a low pressure flash steam cycle (using a condensing steam turbine) is a technically viable option. In general, the ORC is more economically competitive for medium temperature resources, especially for small generating unit sizes.

The most commonly used power cycle in New Zealand has historically been single and multiple flash steam condensing plant (Wairakei, Ohaaki, Kawerau and Nga Awa Purua), however, over the past 10 years GCCU's have dominated with installations at Mokai and Rotokawa. Ormat ORC plants have been installed at Mokai (by Tuaropaki Trust), Rotokawa (by Mighty River Power in partnership with Tauhara North No. 2 Trust), Kawerau (by BOPE), Ngawha (by Top Energy) and at Wairakei (by Contact Energy).

It is worth noting the role of New Zealand's (Aotearoa's) indigenous peoples (the Maori) in recent geothermal developments. At both Mokai and Rotokawa, the Crown has transferred its assets (the geothermal wells) to the local Maori landowners who have then been able leverage these assets in geothermal developments[11,12]. Projects at Ngawha and Kawerau also have Maori equity.

3.3.3 Second hand power plant

Some geothermal developments worldwide have successfully made use of second hand plant including plant which was originally intended for other types of operations, such as marine steam turbines e.g. the back pressure set installed at Kawerau. Other examples of second hand plant use in New Zealand include the high pressure turbines at Ohaaki, the back pressure turbine at Wairakei replacing pressure reducing valves, and the Poihipi station. There can be time and cost savings in doing so. However for the present exercise it is assumed that all plant would be purchased new from the manufacturers.

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[11] http://www.tuaropaki.com/geothermal_power.asp

[12] http://www.tauharano2.co.nz/projects.asp

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4. Geothermal Development Scenarios and Assumptions

A number of generic geothermal development scenarios, typical of the New Zealand geothermal environment, are developed for this study, based on the following considerations.

4.1 Resource Characteristics

A number of physical characteristics of developed and undeveloped geothermal resources which may be available for development in New Zealand are given in Table 4.1. These data show that, for fields likely to be developed, maximum resource temperatures at currently drilled depths in the natural state range from 230 to 330°C with an average value of around 280°C.

- **Table 4-1 Summary of Key Resource Parameters, NZ Geothermal Fields**

Field	Total area of resource	Maximum temperature	Number of deep wells	Maximum drilled depth	Stored Heat Potential	Installed Capacity
	km^2	°C[#]		m	MWe*	MWe
Ngatamariki	12	280	7	2700	120	0
Tokaanu-Waihi	20	*280*	0	~100	200	0
Kawerau	40	315	54	2500	450	132
Mangakino	8	*250*	4	3000	45	0
Mokai	16	*326*	~20	~2500	140	111
Ngawha	18	300	16	2255	160	25
Reporoa	9	230	1	1338	40	0
Rotoma	5	240	1	1450	35	0
Tikitere-Taheke	35	*280*	0	~200	240	0
Ohaaki	10	307	~62	2418	130	92
Rotokawa	20	330	8	3000	300	165
Wairakei	25	271	>50	2255	510	230
Tauhara	35	*300*	8	~2500	320	0
				Totals	2690	755

* at 90% load factor over 50 years

[#] values in *italics* are inferred

Areas and stored heat estimates in Table 4.1 are derived from the estimates in Lawless (2005) with the exception of the stored heat estimate for Ngawha which has been updated to better reflect the actual binary-only power scheme there (which means the basis is not exactly the same as the other fields). Following Lawless (2005), the stored heat capacities take no account of possible environmental limitations as it is the characteristics of the whole resource that are relevant in this context, not the feasibility of development from a regulatory point of view. For several fields there has been significant exploration or development drilling since 2005, which would undoubtedly lead to revisions of these field capacity estimates, but those data are not in the public domain so have not been taken into account, except in so far as in some cases the higher end of the possible range suggested by Lawless (2005) has been used rather than the mean. Where recent published information on temperatures, well numbers and depth is available it has been included. The installed capacity is as of the end of 2008 (Harvey et al., 2010) but also includes the Nga Awa Purua plant at Rotokawa which is almost completed, but not the Contact Energy plant at Tauhara nor the consented Te Mihi expansion which has not yet been started.

4.2 Well Productivity

Average well productivities for New Zealand geothermal fields range from less than 5 $MW.well^{-1}$ (Wairakei, Tauhara, Ohaaki) to more than 20 $MW.well^{-1}$ (Mokai, Rotokawa and more recent wells at Kawerau) and show a strongly bimodal character:

- Wells drilled in the central upflow areas of high temperature (>300 ^{o}C) systems often have well outputs in excess of 20 MW with flowing wellhead pressures ranging from 10 to 30 bara (i.e. Mokai, Rotokawa, Kawerau)
- Wells drilled in more moderate temperature systems (250 to 270 ^{o}C) have well outputs centered on lower values of around 5 MW (e.g. Wairakei, Ohaaki, Tauhara – 250 to 270 ^{o}C) and Ngawha (230 ^{o}C).

On this basis, three resource options have been selected for the costings undertaken in this study, each with the following characteristics:

- High temperature / highly productive resources – e.g. the Mokai, Rotokawa and the Kawerau fields
  - resource temperatures in excess of 300 ^{o}C
  - wells have some excess enthalpy, which is assumed to be 10% above the enthalpy of water at 300 ^{o}C
  - wells have high well head delivery pressures of typically 20 bara
- Medium temperature / moderate productivity resources – e.g. the Wairakei, Ohaaki and Tauhara fields, and the lower temperature part of higher temperature fields.
  - resource temperatures average 260 ^{o}C
  - liquid reservoir conditions with no excess enthalpy
  - wells have moderate wellhead delivery pressures of about 5 bar

- Lower temperature / moderate productivity resources such as Ngawha and outflow zones of higher temperature resources.
  – resource temperatures averaging 230 ^{o}C
  – liquid reservoir conditions with no excess enthalpy
  – wells have moderate wellhead delivery pressures of about 5 bara[13].

Historical data indicate the outputs of New Zealand geothermal wells vary from between 0 and over 30 MW with the average value skewed to a relatively low value of about 4 to 5 MW. This probably reflects that many of the wells were drilled between the 1950's and 1970's when hole depths were typically to 1,200 m and only rarely to greater than 2,000 m depth, and some, such as the early wells at Wairakei and Kawerau, were of smaller diameter than is now considered standard.

Outputs of wells drilled subsequently are often higher due to being drilled to greater depth thus benefiting from both shallow (high enthalpy) and deep (liquid) production zones, and in some cases from having larger diameter production holes and production casings. Future geothermal wells in New Zealand should prove to be better than this past average, due not so much to better well siting ability, but to the use of larger diameter casings and now drilling to greater depth as a matter of routine to target both shallow and deep production. Given this historical data it is reasonable to assume future geothermal wells in New Zealand will have an average output in the range of 5 to 10 MW, i.e. somewhat greater than wells typical of the Wairakei and Ohaaki developments, but significantly less than the larger output wells encountered in the higher temperature, central parts of the Mokai, Rotokawa and Kawerau fields.

Considering the range of resource characteristics discussed above and considering that the development options to be costed need to include a number of different power plant cycle type with efficiencies that vary in response to plant inlet pressure, and well enthalpies (which dictate steam and brine flows), and different thermodynamic efficiencies, it is not very useful for comparative purposes to assign a single average MW rating to wells drilled into the above three resource scenarios. Instead, an “envelope” approach is undertaken here, consistent with the report objectives stated in the Introduction for developing a band of costs.

For each of the three resource options, upper and lower flow rate envelopes have been taken as:

- High envelope of 150 $kg.s^{-1}$ total well flow, and
- Low envelope of 50 $kg.s^{-1}$ of total well flow.

13 Higher wellhead pressures are encountered at Ngawha due to its artesian characteristic, but this is unusual

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Where wells from each of the three resource options are flowed to a single flash condensing steam turbine, then the nominal MW ratings of the wells would be approximately as follows:

Resource Type	High Envelope Flow Rate	Low Envelope Flow Rate
▪ High temperature / highly productive	24 MW	8 MW
▪ Medium temperature / moderate productivity	14 MW	5 MW
▪ Lower temperature / moderate productivity	11 MW	4 MW

4.3 Power Development Size

There is a tension between the economies of scale of larger plants and the requirement of regulatory or investment plans to undertake development in smaller steps.

This study did not look at greenfield developments greater than 50 MW. The main reason is that a greenfield developer would most likely not be able to attract the funds required for a larger development until some experience with the particular resource was gathered and the risks associated with a larger development were able to be well quantified. Furthermore a greenfield development of over 50 MW may struggle to obtain resource consents in New Zealand, given the conservatism of regulatory authorities and their preference for staged developments, for the same reasons.

This contrasts with the current situation in New Zealand where large second stage developments of medium to high temperature resources are occurring at brownfield sites (100 MW at Kawerau and 132 MW at Nga Awa Purua (Rotokawa)). This implies that the anticipated returns on these investments within the current electricity market in New Zealand are attractive – and developers are on record as stating that "Geothermal is the lowest cost source of new generation for New Zealand[14]".

4.4 Power plant cycle type

Each of the four power cycle types described in Section 3.3 can be used for generating geothermal power from the three resource types described above, however, the single flash non-condensing steam plant and the hybrid steam / binary plant options are better suited to high temperature / high delivery pressure resource conditions. The efficiency of flash steam plant at lower temperature resource conditions (e.g. Option 3 at 230 ^{o}C) is much lower due to the limited steam flash from water at these temperatures. ORC power options using separated brine, with or without steam, are the most efficient option for utilising geothermal fluids at these conditions.

[14] Baldwin, D. (2008). Chief Executive's Review. http://www.contactenergy.co.nz/web/pdf/financial/ar_20080923_chairman_ceo_review.pdf

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4.5 Study Options

Based on the discussion above, options for detailed costing in this study have been developed for the following:

- 3 resource types (>300, 260 and 230 ^{o}C)
- 2 well flow envelope bands (of 50 and 150 $kg.s^{-1}$)
- 4 power plant cycle types, and
- 2 power plant capacities, 20 and 50 MW.

These various options have then been combined into 32 scenarios as detailed in Table 4.2.

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Table 4-2 Summary of Geothermal Development Costing Options

Option #	Reservoir Temperature (°C)	Well Flow Envelope	Development Size MW	Power Plant (Cycle Type)
1	300	High	50	Single Flash
2	260	High	50	Single Flash
3	260	High	20	Single Flash
4	230	High	20	Single Flash
5	300	High	50	Double Flash
6	260	High	50	Double Flash
7	260	High	20	Double Flash
8	230	High	20	Double Flash
9	300	High	50	Hybrid
10	260	High	50	Hybrid
11	260	High	20	Hybrid
12	230	High	20	Hybrid
13	300	High	50	ORC
14	260	High	50	ORC
15	260	High	20	ORC
16	230	High	20	ORC
17	300	Low	50	Single Flash
18	260	Low	50	Single Flash
19	260	Low	20	Single Flash
20	230	Low	20	Single Flash
21	300	Low	50	Double Flash
22	260	Low	50	Double Flash
23	260	Low	20	Double Flash
24	230	Low	20	Double Flash
25	300	Low	50	Hybrid
26	260	Low	50	Hybrid
27	260	Low	20	Hybrid
28	230	Low	20	Hybrid
29	300	Low	50	ORC
30	260	Low	50	ORC
31	260	Low	20	ORC
32	230	Low	20	ORC

5. Steamfield Development Assumptions and Requirements

5.1 Steamfield Development Assumptions

Well and steamfield development layouts are needed to size and cost geothermal fluid collection and disposal systems.

The areal size of a resource required for development is determined by field power density, and a value of 12.5 $MW.km^{-2}$ has been used to determine approximate well spacings and, hence, steamfield piping layouts in this study. It does not have any other effect on costs. Where resource characteristics are very favourable it would be possible to adopt a higher density, however, for the present study 12.5 $MW.km^{-2}$ is taken as a good working average value for the New Zealand geothermal environment as a reasonable balance between minimising cost and avoiding possible problems with excessive local adverse reservoir and environmental effects.

Well spacing refers to the separation at the feed points of wells. Production and reinjection wells should be separated by at least 500 m and preferably over 1,000 m. In practice multiple directional wells may be drilled from multi well cellars located on a single well pad, thus wellheads may be located much closer together than indicated by well feed zone spacing distance.

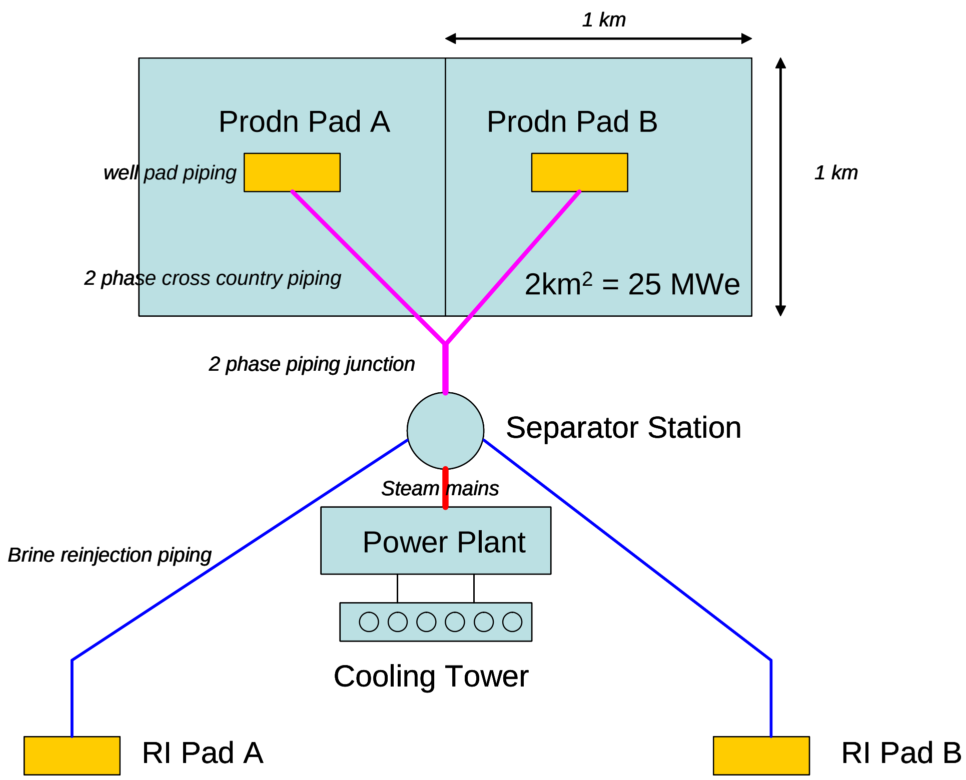
A conceptual steamfield development layout as shown in Figure 5-1 has been assumed in this study. This shows, for a 50 MW development, two multi well pads located in the central resource area of a geothermal field. A resource area of at least 2 km^2 can be accessed from each multi well pad with deviated wells of 800 m or more throw. Two-phase geothermal fluids are piped via two-phase cross country pipe lines from the well pads to a single-vessel 50 MW separator station and power plant located towards the edge of the field. Separated steam is piped from the separator to the power plant and separated waste brine is piped to two separate reinjection pads located further off the field, one of which would include condensate reinjection. For the purpose of pipeline costing the following nominal pipe line lengths have been assumed:

- Cross country piping to junction = 1,200 m
- Junction to steam/brine separator = 50 m
- Separator to power plant = 100 m
- Separator to each brine injection pad = 1,500 m

In addition to the piping and well requirements, civil engineering costs for well pad and cellars preparation, and roading to each of the production and injection well pads are also included in the steamfield costing.

For a 20 MW development, only one production pad and one reinjection pad is assumed.

Pumped injection of brine has been costed into all development options (but no allowance has been made in the financial modelling for brine pumping parasitic power requirements when calculating the net kWh of each development option).



- **Figure 5-1 Conceptual Field Development Layout**

5.2 Well Requirements

Mass flow requirements for the 32 options for both production and reinjection wells and the two power plant development sizes of 20 and 50 MW are detailed in Table 5-1 and Table 5-2.

5.2.1 Start Up

Well requirements at the commencement of each geothermal development option have been calculated by the following procedure:

- "High envelope" wells are allocated a total mass flow (TMF) of 150 $kg.s^{-1}$ and "low envelope wells" a TMF of 50 $kg.s^{-1}$

- Well enthalpies are assumed to be that for liquid at reservoir temperatures, except for the high temperature / high pressure resource options (300 ^{o}C options) in which case a 10% excess enthalpy is assumed (as a result of either pressure drawdown and excess enthalpy effects or shallow addition of higher enthalpy fluids to well discharges)
- First Stage Separation pressures (SP1) have been set as low as possible to maximise steam flash, constrained by a lower limit where silica saturation ratio increases to approach 1.15 at which level and above silica deposition starts to become a significant problem in the reinjection system. This design approach results in:
  - a very high SP1 of 19 bara being required for the 300 ^{o}C resource option (due to high dissolved silica levels in the reservoir brine at these temperatures)
  - 5 bara for the 260 ^{o}C options
  - 3 bara for the 230 ^{o}C development options
- Second Stage Separator pressures (SP2) have also been set as low as possible to maximize the second stage flash, constrained by a lower limit where the silica saturation ratio approaches 1.30. At this level silica deposition is a real concern and the waste brine flow from the second flash separator will require some form of chemical treatment to prevent silica deposition, such as acid dosing, and
- With the mass flows and the steam flash now defined for each development option, together with the known specific energy consumption for each power plant option, the electrical generating capacity of the wells can be established. The number of production wells on each wellpad is then increased one by one until the production capacity of the pad just exceeds 100% of the 20 or 50 MW development requirement. This establishes the startup production well requirements for each development. Where production capacity does not exceed 100% of the startup requirement an additional well is drilled in the first year of operation.

■ Table 5-1 Well Requirements for High Envelope Options # 1 to # 16

Scenario #			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Field Type	Reservoir T	°C	300	260	260	230	300	260	260	230	300	260	260	230	300	260	260	230
	Nominal development size	MW	50	50	20	20	50	50	20	20	50	50	20	20	50	50	20	20
	Power Cycle Type (SF, DF)		SF	SF	SF	SF	DF	DF	DF	DF	Hybrid	Hybrid	Hybrid	Hybrid	ORC	ORC	ORC	ORC
Well Requirements	Average well TMF	*kg/sec*	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
	Number of production wells required?	*#*	2	4	2	2	2	4	2	2	2	3	2	2	3	4	2	3
	Number of injection wells required	*#*	2	3	2	2	2	3	2	2	2	3	2	2	3	4	2	2
	Sum of MW	*MW*	**53.6**	**57.3**	**28.7**	**20.3**	**60.5**	**64.4**	**32.2**	**23.0**	**56.2**	**55.1**	**31.2**	**21.3**	**74.0**	**55.9**	**28.0**	**29.4**
	Avge well Output	*MW/well*	26.8	14.3	14.3	10.2	30.2	16.1	16.1	11.5	28.1	18.4	15.6	10.7	24.7	14.0	14.0	9.8
Conversion Factors:	Heat Rate	*MWth/MW*	7.53	11.88	11.88	14.60	6.67	10.58	10.58	12.94	7.18	9.27	10.91	13.92	8.18	12.17	12.17	15.14
	Specific steam consumption HP turbine	*kg/sec/MW*	1.7	2.5	2.5	2.9	1.7	2.5	2.5	2.9								
	Specific steam consumption LP turbine	*kg/sec/MW*	0	0	0	0	2.0	3.1	3.1	3.9								
	Injection / Prodn well mass ratio		0.83	0.77	0.77	0.67	0.83	0.77	0.77	0.67	0.83	0.77	0.77	0.67	0.83	0.77	0.77	0.67
Reservoir Conditions:	Reservoir T	°C	300	260	260	230	300	260	260	230	300	260	260	230	300	260	260	230
	Fluid H	*kJ/kg*	1,345	1,135	1,135	990	1,345	1,135	1,135	990	1,345	1,135	1,135	990	1,345	1,135	1,135	990
	Excess H	*%*	10%	0%	0%	0%	10%	0%	0%	0%	10%	0%	0%	0%	10%	0%	0%	0%
	Total Fluid H	*kJ/kg*	1,479	1,135	1,135	990	1,479	1,135	1,135	990	1,479	1,135	1,135	990	1,479	1,135	1,135	990
Separator Parameters:	SP1	*MPaa*	1.90	0.50	0.50	0.30	1.90	0.50	0.50	0.30	1.90	1.00	0.50	0.30	1.90	0.50	0.50	0.30
	ST1	°C	210	152	152	134	210	152	152	134	210	180	152	134	210	152	152	134
	SP2 (for double flash)	*MPaa*					1.00	0.25	0.25	0.15					1.90	0.50	0.50	0.30
	ST2	°C					180	127	127	111					210	152	152	134
First Flash:	X1		0.306	0.235	0.235	0.198	0.306	0.235	0.235	0.198	0.306	0.185	0.235	0.198	0.306	0.235	0.235	0.198
	SF1	*kg/sec*	92	141	70	59	92	141	70	59	92	83	70	59	138	141	70	89
	WF1	*kg/sec*	208	459	230	241	208	459	230	241	208	367	230	241	312	459	230	361
	TMF1		300	600	300	300	300	600	300	300	300	450	300	300	450	600	300	450
Second Flash:	X2	*kg/sec*					0.067	0.048	0.048	0.042					-	-	-	-
	SF2	*kg/sec*					14	22	11	10					-	-	-	-
	WF2	*kg/sec*					194	437	219	230					-	-	-	-
	TMF2						208	459	230	241					-	-	-	-
Plant Output:	MW HP condensing	*MW*	53.6	57.3	28.7	20.3	53.6	57.3	28.7	20.3	-	-	-	-	-	-	-	-
	MW LP condensing	*MW*					6.9	7.0	3.5	2.6	-	-	-	-	-	-	-	-
	MW GCCU - based on overall efficiency	*MW*									-	-	-	-	-	-	-	-
	MW GCCU BP Turbine	*MW*	-	-	-	-	-	-	-	-	26.6	17.8	9.5	4.7	-	-	-	-
	MW OEC steam	*MW*	-	-	-	-	-	-	-	-	19.7	17.8	15.1	12.7	59.1	42.7	21.4	23.5
	MW OEC binary	*MW*	-	-	-	-	-	-	-	-	9.9	19.5	6.6	3.9	14.9	13.2	6.6	5.9
	MW Total	*MW*	53.6	57.3	28.7	20.3	60.5	64.4	32.2	23.0	56.2	55.1	31.2	21.3	74.0	55.9	28.0	29.4
Well Requirements:	Required # production wells		2	4	2	2	2	4	2	2	2	3	2	2	3	4	2	3
	TMF each prodn well	*kg/sec*	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
	Capacity each injection well	*kg/sec*	180	195	195	225	180	195	195	225	180	195	195	225	180	195	195	225
	Brine for injection	*kg/sec*	208	459	230	241	194	437	219	230	297	446	297	297	446	594	297	446
	Required # injecn wells		2	3	2	2	2	3	2	2	2	3	2	2	3	4	2	2
Silica Issues:	SSI SP1	-	1.14	1.12	1.12	0.92	1.14	1.12	1.12	0.92	1.14	0.83	1.12	0.92	1.14	1.12	1.12	0.92
	SSI at SP2	-	-	-	-	-	1.54	1.50	1.50	1.21	-	-	-	-	-	-	-	-
	SSI in (ORCstm + ORCbinary) exit mix	-					-	-			1.51	1.50	1.50	1.07	1.51	1.50	1.50	1.07

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▪ Table 5-2 Well Requirements for Low Envelope Options # 17 to # 32

Scenario #			17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32
Field Type	Reservoir T	°C	300	260	260	230	300	260	260	230	300	260	260	230	300	260	260	230
	Nominal development size	MW	50	50	20	20	50	50	20	20	50	50	20	20	50	50	20	20
	Power Cycle Type (SF, DF)		SF	SF	SF	SF	DF	DF	DF	DF	Hybrid	Hybrid	Hybrid	Hybrid	ORC	ORC	ORC	ORC
Well Requirements	Average well TMF	*kg/sec*	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
	Number of production wells required?	*#*	6	11	5	6	5	10	4	6	6	9	4	6	7	11	5	7
	Number of injection wells required	*#*	4	7	3	4	3	6	3	4	5	7	4	4	6	9	4	5
	Sum of MW	*MW*	**53.6**	**52.5**	**23.9**	**20.3**	**50.4**	**53.6**	**21.5**	**23.0**	**56.2**	**55.1**	**20.8**	**21.3**	**57.6**	**51.3**	**23.3**	**22.9**
	Avge well Output	*MW/ well*	8.9	4.8	4.8	3.4	10.1	5.4	5.4	3.8	9.4	6.1	5.2	3.6	8.2	4.7	4.7	3.3
Conversion Factors:	Heat Rate	*MWth / MW*	7.53	11.88	11.88	14.60	6.67	10.58	10.58	12.94	7.18	9.27	10.91	13.92	8.18	12.17	12.17	15.14
	Specific steam consumption HP turbine	*kg/sec/MW*	1.7	2.5	2.5	2.9	1.7	2.5	2.5	2.9								
	Specific steam consumption LP turbine	*kg/sec/MW*	0	0	0	0	2.0	3.1	3.1	3.9								
	Injection / Prodn well mass ratio		0.83	0.77	0.77	0.67	0.83	0.77	0.77	0.67	0.83	0.77	0.77	0.67	0.83	0.77	0.77	0.67
Reservoir Conditions:	Reservoir T	°C	300	260	260	230	300	260	260	230	300	260	260	230	300	260	260	230
	Fluid H	*kJ /kg*	1,345	1,135	1,135	990	1,345	1,135	1,135	990	1,345	1,135	1,135	990	1,345	1,135	1,135	990
	Excess H	*%*	10%	0%	0%	0%	10%	0%	0%	0%	10%	0%	0%	0%	10%	0%	0%	0%
	Total Fluid H	*kJ /kg*	1,479	1,135	1,135	990	1,479	1,135	1,135	990	1,479	1,135	1,135	990	1,479	1,135	1,135	990
Separator Parameters:	SP1	*MPa abs*	1.90	0.50	0.50	0.30	1.90	0.50	0.50	0.30	1.90	1.00	0.50	0.30	1.90	0.50	0.50	0.30
	ST1	°C	210	152	152	134	210	152	152	134	210	180	152	134	210	152	152	134
	SP2 (for double flash)	*MPa abs*					1.00	0.25	0.25	0.15					1.90	0.50	0.50	0.30
	ST2	°C					180	127	127	111					210	152	152	134
First Flash:	X1		0.306	0.235	0.235	0.198	0.306	0.235	0.235	0.198	0.306	0.185	0.235	0.198	0.306	0.235	0.235	0.198
	SF1	*kg/sec*	92	129	59	59	77	117	47	59	92	83	47	59	107	129	59	69
	WF1	*kg/sec*	208	421	191	241	173	383	153	241	208	367	153	241	243	421	191	281
	TMF1		300	550	250	300	250	500	200	300	300	450	200	300	350	550	250	350
Second Flash:	X2	*kg/sec*					0.067	0.048	0.048	0.042					-	-	-	-
	SF2	*kg/sec*					12	18	7	10					-	-	-	-
	WF2	*kg/sec*					162	364	146	230					-	-	-	-
	TMF2						173	383	153	241					-	-	-	-
Plant Output:	MW HP	*MW*	53.6	52.5	23.9	20.3	44.7	47.8	19.1	20.3	-	-	-	-	-	-	-	-
	MW LP	*MW*					5.7	5.9	2.3	2.6	-	-	-	-	-	-	-	-
	MW GCCU - based on overall efficiency	*MW*									-	-	-	-	-	-	-	-
	MW GCCU BP Turbine	*MW*	-	-	-	-	-	-	-	-	26.6	17.8	6.4	4.7	-	-	-	-
	MW OEC steam	*MW*	-	-	-	-	-	-	-	-	19.7	17.8	10.0	12.7	46.0	39.2	17.8	18.3
	M We OEC binary	*MW*	-	-	-	-	-	-	-	-	9.9	19.5	4.4	3.9	11.6	12.1	5.5	4.6
	MW Total	*MW*	53.6	52.5	23.9	20.3	50.4	53.6	21.5	23.0	56.2	55.1	20.8	21.3	57.6	51.3	23.3	22.9
Well Requirements:	Required # production wells		6	11	5	6	5	10	4	6	6	9	4	6	7	11	5	7
	TMF each prodn well	*kg/sec*	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
	Capacity each injection well	*kg/sec*	60	65	65	75	60	65	65	75	60	65	65	75	60	65	65	75
	Brine for injection	*kg/sec*	208	421	191	241	162	364	146	230	297	446	198	297	347	545	248	347
	Required # injecn wells		4	7	3	4	3	6	3	4	5	7	4	4	6	9	4	5
Silica Issues:	SSI SP1	-	1.14	1.12	1.12	0.92	1.14	1.12	1.12	0.92	1.14	0.83	1.12	0.92	1.14	1.12	1.12	0.92
	SSI at SP2	-	-	-	-	-	1.54	1.50	1.50	1.21	-	-	-	-	-	-	-	-
	SI in (ORCstm + ORCbinary) exit mix	-					-	-			1.51	1.50	1.50	1.07	1.51	1.50	1.50	1.07

- Silica saturations from Hybrid and ORC plant have high silica saturations of typically in excess of 2.0 at the exit of the brine ORC units. With conventional geothermal plant, this would lead to rapid deposition of silica, however, it is assumed that with ORC plant the condensed steam (from the steam binaries) and the spent brine flows (from the brine binaries) are recombined downstream of the plant and the dissolved gas load from the steam ORC produces a reduction in the pH of the total fluid mix. This very usefully delays the onset of silica polymerization and deposition and allows for these otherwise unacceptably high silica saturations to be tolerated. For the purpose of this calculation, the exhaust temperature of the brine ORC has been set at the temperature at which silica saturation in the mixed condensed steam + brine are maintained at no greater than 1.5.
- The number of injection wells required for a geothermal development is determined by the injection capacity of each well. In the calculations given in Table 5-1 and Table 5-2 the capacity of injection wells are linked to the capacity of production wells by an Injection / Production well mass ratio. This ratio varies from 0.87 to 0.62 (which is equivalent to injection wells having from 120% to 150% greater capacity than the flows from the production wells). The lower ratio has been used for lower separator pressures / temperatures options where brine density is higher.

5.2.2 Make Up and Replacement Well Capacity

During the production life of a geothermal field, gradual reservoir pressure drawdown results in mass flows from production wells reducing with time and this results in reduced steam flows (in the absence of excess enthalpy effects). The geothermal field operator will compensate for this by drilling additional wells with time to provide additional steam flow to bring total well output up to the full load requirement of the power plant. These additional wells are known as “M&R” wells (makeup and replacement wells).

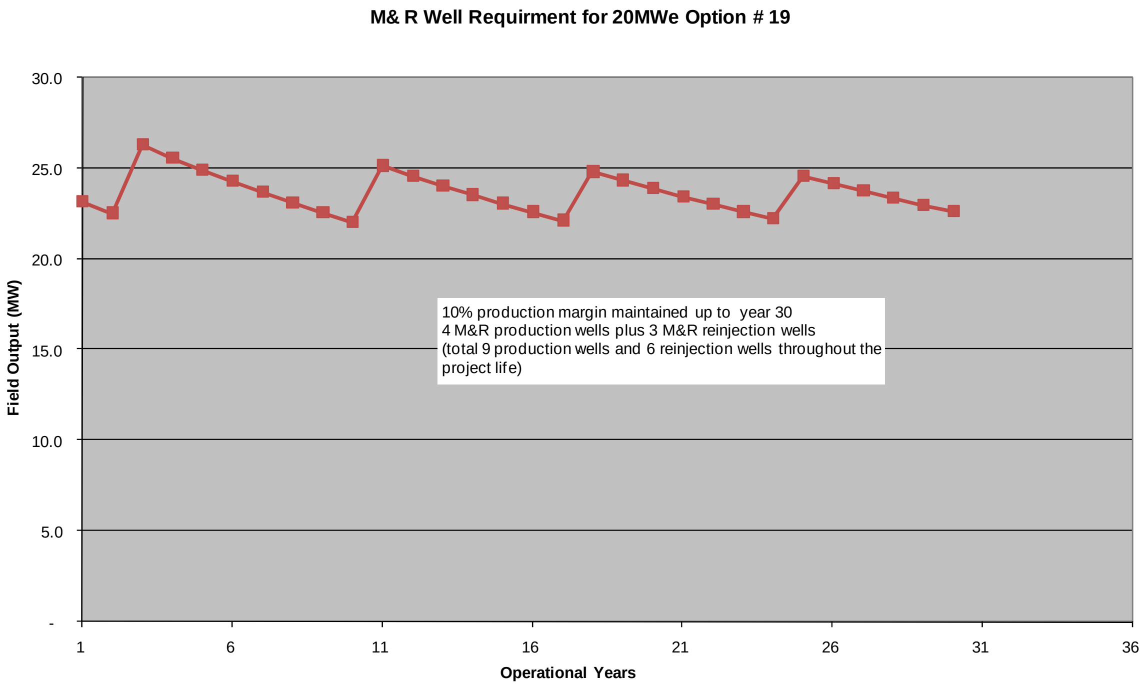
The actual rate of reservoir pressure rundown tends to be site specific and is determined closely by the size of the development in relation to the size of the reservoir, the extent to which reinjection is practiced (which provides reservoir pressure support and which can reduce the rate of reservoir pressure decline), and the rate of reservoir recharge. In order to determine the rates of reservoir rundown at specific sites with some level of precision, detailed numerical modeling studies are undertaken prior to the development and these are subsequently recalibrated and validated against the results of the actual reservoir performance during production.

For the purpose of this cost study, an adequate representation of reservoir pressure run down with time can be approximated by a harmonic decline equation (Sanyal, 2005):

$$W = W_i \ / (1+D_i * t)$$

where W_i is initial productivity, D_i is the initial annual decline rate in productivity and W is productivity in year t.

For geothermal developments in the size range of 20 to 50 MW in an otherwise undeveloped field, annual production well decline rates of 3% are typical. This value has been assumed in this study to predict M&R requirements. An example of a decline analysis is given in Figure 5-2 for development Option # 19 from Table 5-2 with 5 production wells initially required at start up. A further 6 M& R wells are predicted to be required throughout the 30 year production life with the timing of individual wells as indicated. This M&R well sequence for Option # 19 would allow for production from the field to be maintained at 10% above the power plant requirement from Operational Year 1 to Year 30, providing a buffer should a production well require to be taken offline for maintenance purposes.



- **Figure 5-2 Example of Harmonic Decline Analysis**

6. Cost Assumptions

The following cost assumptions have been made in building up an overall definition of geothermal capital and operating costs for the development scenarios detailed in the previous chapter.

6.1 Establishment Costs

A total of NZD 3.0 million has been allowed for establishment costs associated with a 20 MW development, and NZD 3.5 million for a 50 MW development. These costs include:

- Permitting
- Land acquisition
- Geoscientific / Environmental
- Well Testing
- Civil works and Infrastructure
- Site Operations, and
- Pre Feasibility/ Feasibility Reports.

6.2 Drilling Costs

Well drilling costs can vary significantly depending on the depth and size of wells to be drilled, the capability of the rig, the number of holes to be drilled (which allows rig mobilisation cost to be shared over a number of wells), topography and site access generally, and the drilling conditions encountered.

Well costs as given in

Table 6-1 are assumed. Given the level of these costs the drilling of wells with large well outputs is clearly advantageous to project economics. The high level of drilling costs also emphasises the importance of achieving the highest possible drilling success rate throughout exploration, delineation and production drilling programs. The need for thorough geoscientific work at the pre-drilling phase and throughout later drilling is thus evident. This can be highly cost effective because of the low cost of scientific work compared to the high cost of drilling.

It is important to note that well drilling costs have increased considerably over the last few years and upward movement in the cost of drilling rigs and drilling equipment continues. This is discussed in more detail in Section 7.3.

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Table 6-1 Estimated Geothermal Drilling Costs in New Zealand (2007)*

Well Drilling Operation	Estimated Total Cost NZD M[15]	Estimated Total Cost (at E/R 0.70) USD M	Local Content %	Local Cost Component NZD M	Overseas Cost Component (at E/R 0.70) USD M
Production well (work-over existing)	0.3	0.2	50%	0.2	0.1
	to 1.0	to 0.7	50%	0.5	0.4
Production well (1,500m)	3.2	2.2	40%	1.3	1.3
Production well (2,500m)	5.2	3.6	40%	2.1	2.2
Reinjection well (2,000m)	4.2	2.9	40%	1.7	1.8

** exclusive of rig mobilisation and demobilisation costs*

The allocation of drilling costs into NZD and USD components is based on the percentages given in Table 6-1. These have been determined from the analysis of budgets and actual costs for recent geothermal wells in New Zealand. These range from 50% local / 50% overseas costs for well workovers, to 40% local / 60% overseas costs for new wells.

Key assumptions in these local / foreign currency allocations are:

- Drilling rig rental costs are relatively insensitive to whether rigs are sourced from within New Zealand or from overseas. This is because the highly competitive current state of the international oil and gas industry has established a more or less global rig rate.
- Drilling mobilisation costs are, however, country specific. It is assumed in this study that drilling rigs are available in New Zealand close to areas of geothermal interest and a nominal drilling mobilisation /demobilisation cost of NZD 1,300,000 x 2 per round trip will apply in addition to the drilling costs given in Table 6.1. In contrast, mobilization / demobilization costs for rigs coming into New Zealand from overseas will be significantly higher.
- The most significant local components of drilling rig costs are rig labour (about 30%) and cement / cementing services (10%).
- The most significant overseas components of drilling costs are drilling fluids (about 15%), drilling tools and drill bits (15%), casing and wellhead valves (15%) and rig rental (15%).

[15] M = million

6.3 Steamfield Costs

Steamfield development costs have been assessed using a bottom-up approach based on the following considerations:

- Steamfield piping

This includes two phase piping, separators, steam and brine piping and reinjection pumps to take geothermal fluid from the production wells to the power plant, and dispose of waste fluids to reinjection wells. The numbers of wells required and mass flow rates are as detailed in Table 5-1 and Table 5-2 for each of the "high well flow" and "low well flow" development scenario. These dictate piping sizes. The required piping lengths have been obtained from the steamfield concept layout in Figure 5-1. Based on this information, a piping schedule has been drawn up and costed. Approximately 30% of the total piping cost is allocated to piping materials procurement in foreign currency and the balance of 70% is for pipeline erection allocated in NZD.

- Steamfield plant

These items include line valves and instrumentation, and steam / water production separators and brine pumps for either 20 or 50 MW size depending on development options. Estimated foreign currency cost allocations for these are 100%, 50% and 80% respectively.

- Site Civil Works

This requirement includes preparation of site roading, separator station foundations, well pads and multi well cellars. These costs are allocated 100% to local currency.

Within the precision of this study, the steamfield development requirements are assumed to be the same for the single flash, hybrid steam + binary and the pure ORC options, as they involve the same piping layout and control systems and a single separation in each case. The double flash option is more complex, involving a greater cost due to the requirement for a second flash vessel / separator, more piping around the separator station, further instrumentation and additional civil works.

Estimated steamfield development costs for the various options are given in Table 6.2. These capital costs are carried forward into Section 7 where they are used to build up a total capital cost for each of the 32 project development scenarios.

The overall balance of New Zealand costs to overseas costs is estimated at about 80% for both the 20 and 50 MW plants.

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- **Table 6-2 Estimated Steamfield Development Costs (2007)**

		50 MWe Steamfield System - NZD		20 MWe Steamfield System - NZD		Overseas	NZ
Item	Description	SF, GCCU, ORC	Dual flash steam	SF, GCCU, ORC	Dual flash steam	Cost	Cost
1	Preliminaries & General	2,800,000	3,300,000	1,500,000	1,800,000	0%	100%
2	Civil / Structural Works	9,700,000	11,400,000	5,300,000	6,200,000	0%	100%
3	Mechanical Works	14,800,000	17,500,000	6,200,000	7,400,000	40%	60%
4	Control & Instrumentation	500,000	600,000	200,000	300,000	80%	20%
5	Electrical Work	500,000	500,000	200,000	200,000	0%	100%
6	Miscelllaneous	1,000,000	1,000,000	600,000	600,000	10%	90%
7	Engineering and Design	3,200,000	4,000,000	1,800,000	2,200,000	20%	80%
	Total Estimated EPC cost	32,500,000	38,300,000	15,800,000	18,700,000		
	$NZD.kWe^{-1}$ gross power	650	770	790	940		
	NZD Cost	25,400,000	29,900,000	12,700,000	15,000,000		
	Overseas Cost	7,100,000	8,400,000	3,100,000	3,700,000		
	% NZD Cost	78%	78%	80%	80%		
	% Overseas Cost	22%	22%	20%	20%		

6.4 Power Plant Costs

Power plant costs are affected by competition between suppliers, current order status, commodity prices, the commercial terms and/or scope of supply, and the particular project contract interfaces for geothermal fluid supply and/or electricity export. It is therefore difficult to give a precise price for a geothermal power plant in advance of tendering.

Plant size is a significant cost factor, especially in the case of single unit condensing steam turbines, but less so for ORC plants which are typically modular. Other factors to consider are the optimisation of condenser pressure (and attendant effects on cooling system operation), means of gas extraction, and the use of standard (modular) power units.

There is likely to be considerable variation in power plant price due to the choice of supplier, its country of origin (Japan, USA, Italy, France, Israel and Germany), and the choice of power cycle. Nonetheless, through the analysis of historic power plant cost and after adjustment for recent price trends reasonably representative capital cost estimates can be developed for geothermal power plant.

6.4.1 Single pressure condensing power plant

For condensing steam turbine generating units, there are significant economies of scale with specific capital cost ($\$.MW^{-1}$) decreasing with increasing unit size. Present day costs (as at 2007) are assessed in Table 6-3. These estimates cover all power plant-related works including site establishment, civil works, mechanical and electrical installation works (of main generating equipment and balance of plant supplied from overseas and / or locally where feasible), (11 kV) switchboard for main generator output, auxiliary loads supply (3.3 kV and 415 V), step-up transformer (11/110 or 11/220 kV) and 110 / 220 kV switchyard (single bay). The high voltage transmission line is not included in this price but is costed separately.

It is assumed that the power plant will be supplied under an engineer, procure and construct (EPC) contract[16]. Provision for major spare parts is included in the EPC price.

- **Table 6-3 Estimated Costs for Single Pressure Condensing Power Plant (2007)**

Plant Size	Estimated Total Cost NZD per kW installed	Estimated Total Cost USD per kW installed (E/R[17] 0.70)	Local Cost Component NZD M	Overseas Cost Component USD M (E/R 0.70)
20 MW single unit	2,200	1,540	8.8	24.6
50 MW single unit	1,900	1,330	19.0	53.2

6.4.2 Double pressure condensing power plant

Present day costs (as at 2007) for power plant with double pressure turbines of 20 and 50 MW capacity are assessed in Table 6-4. These estimates cover all power plant related works and items detailed in the section above for single pressure non condensing plant.

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[16] EPC Contract - Engineer Procure Construct Contract. This is a contract arrangement in which a contractor assumes total responsibility, under contract to the project owner (developer), for the design, procurement, construction and commissioning of e.g. a power plant. The contract conditions will normally be based on a fixed contract sum and will specify a time for completion to which the contractor commits and a performance guarantee, beyond which liquidated damages may be claimed, reflecting the value of the loss that the owner faces due to the late completion or the off-guarantee performance. These damages may include items such as the cost of financing, penalty costs the owner may be charged for performance shortfall under its power sales agreement (if any), additional charges for engineering supervision and the like.

[17] E/R = exchange rate, $NZD.USD^{-1}$

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It is assumed that the power plant will be supplied under an EPC contract. Provision for major spare parts is included in the estimated EPC price.

- **Table 6-4 Estimated Costs for Double Pressure Condensing Power Plant (2007)**

Plant Size	Estimated Total Cost NZD per kW installed	Estimated Total Cost USD per kW installed (E/R 0.70)	Local Cost Component NZD M	Overseas Cost Component USD M (E/R 0.70)
20 MW single unit	2,450	1,720	9.8	27.5
50 MW single unit	2,100	1,470	21.0	58.8

6.4.3 Organic Rankine Cycle Plant

Standalone ORC power plant units are commercially available in a range of sizes, typically 2 MW, 5 MW and 10 MW. Since the largest unit sizes are only about 10 MW at present, larger ORC plant projects use multiple units, and there are limited economies of scale when units are replicated because heat exchanger area increases with heat load (power output), and the air cooled condensers typically used on ORC plants are assemblages of individual air cooler "modules", so the cost of condensers increases approximately pro-rata with output (and hence heat load rejected).

Other parts of an ORC plant, such as turbines, generators, switchgear, transformers, and piping may have some economies of scale but, taken overall, the economies of scale on power plant costs are quite minor, and other factors are often of greater importance. These include competition between plant suppliers, current order status of suppliers, world-wide commodity prices, the particular commercial terms and/or scope of supply utilised (e.g. ex-works and/or FOB and/or CIF supply, through to full EPC or "turn-key" contract), and the actual contract interfaces at the project site (for geothermal fluid supply and/or electricity export).

Published cost data on ORC power plant installed in New Zealand are limited to the Ngawha I power plant, described by Frederiksens (et. al., 2000) as follows.

The Ngawha 1 plant is a 9.3 MW net pure ORC plant, commissioned in 1997 at a cost of USD 17 million which included supply and installation of both steamfield piping plus power plant.

Assuming an annual average cost increase of 2.5% per annum from 1998 to 2007 and converting the adjusted USD to NZD at an exchange rate of 0.70 indicates that a similar size development in 2007 would cost about NZD 31M, representing an installed cost of about NZD 3,350 per kW. This value is believed to be similar to that for the Ngawha II plant which has recently been completed.

For the purposes of the present study this cost figure has been used directly for assessing the current cost of a 20 MW ORC power plant undertaken on an EPC basis, the scope of which is comparable to the single or double flash condensing steam turbine cycles. Provision for major spare parts is included in the EPC price.

On the basis of the comments above on the modular nature of the ORC plant not providing any significant economies of scale the same specific cost has been used for both the 20 and 50 MW plants.

- **Table 6-5 Estimated Costs for ORC Power Plant (2007)**

Plant Size	Estimated Total Cost NZD per kW installed	Estimated Total Cost USD per kW installed (E/R 0.70)	Local Cost Component NZD M	Overseas Cost Component USD M (E/R 0.70)
20 MW + steamfield piping	3,350	2,350	13.4	37.6
50 MW + steamfield piping	3,350	2,350	33.5	94.0
20 MW power plant	2,700	1,890	10.8	30.2
50 MW power plant	2,700	1,890	27.0	75.6

Using the steamfield development cost estimates given in Table 6.2, power plant only costs for the pure ORC option of 2,700 NZD.kW^{-1} installed have been derived as shown in Table 6.5 and these values have been used in the capital cost calculations in Tables 7.1 and 7.2 for both the 50 and 20 MW plant sizes.

6.4.4 Hybrid Steam + ORC Binary Plant

Hybrid projects using a combination of back pressure steam turbine and ORC units. Units manufactured by Ormat with this configuration are termed GCCU's – geothermal combined cycle units

In the New Zealand market place, many of the recent geothermal projects have used Ormat equipment, reputedly because capital cost and supplier credits were key determinants in selecting the plant supplier. Based on available information, the cost of Ormat hybrid steam + binary unit power plants, marketed under the trade name Geothermal Combined Cycle Units ("GCCU"), has been in the range of about NZD 2.0 million.MW^{-1} to NZD 2.5 million.MW^{-1} (including civil works and infrastructure costs but not transmission).

GCCU's installed at geothermal fields in New Zealand include:

- Mokai I (59MW), Mokai II (39 MW) and Mokai 1A (expansion which involves a retrofit of a larger non condensing steam turbine at the Mokai I plant)

  The Mokai II plant was committed in 2003 at a cost of NZD 90 million for the power plant and steamfield piping requirements (equal to USD 52 million at the exchange rate prevailing at that time) for a gross output of 40 MW[18]. This gives a specific capital cost of about NZD 2,200. kW^{-1} after correction for inflation and exchange rate changes.

- Rotokawa I Plant

  This 24 MW GCCU plant was commissioned in 1996 at a cost of USD 34 million which included supply and installation of both steamfield piping plus power plant. Assuming an annual cost increase of 2.5% per annum from 1996 to 2007 (10 years) and converting the adjusted USD to NZD at an exchange rate of 0.70 indicates a similar size development in 2007 would cost about NZD 63[19] million, representing an installed cost of about NZD 2,600.kW^{-1}.

For the purposes of the present study costs for hybrid steam + binary cycle plant are assessed as follows, supplied under an EPC contract, the scope of which is comparable to the other cycles considered. Provision for major spare parts is included in the EPC price:

- **Table 6-6 Estimated Costs for Hybrid Steam + Binary Cycle Power Plant (2007)**

Plant Size	Estimated Total Cost NZD per kW installed	Estimated Total Cost USD per kW installed (E/R 0.70)	Local Cost Component NZD M	Overseas Cost Component USD M (E/R 0.70)
20 MW	2,600	1,820	10.4	29.1
50 MW	2,200	1,610	23.0	64.4

6.5 Transmission Interconnection Costs

The geothermal power plant is assumed to be located in the vicinity of the national 220 kV transmission network. Transmission of 20 to 50 MW at 110 kV is technically and economically feasible, but consideration of this would not provide a sufficiently conservative cost.

A reliable arrangement for the interconnection of a power plant to an existing transmission line is through the deviation of the transmission line into the power plant switchyard. The cost of a 20 km

[18] NZ Herald, 11 August 2003

[19] =34*(1.025)^10/0.70

heavy duty double circuit 220 kV transmission line is estimated at NZD 4 million and the associated transformer an additional NZD 2 million and 3 million for the 20 and 50 MW developments respectively. Switchyard, substation, consenting and easement costs are not included in these estimates.

6.6 Operating and Maintenance Costs

Operating and Maintenance (O&M) costs for geothermal projects include the costs of operating and maintaining both the power plant and the steamfield fluid gathering and handling system.

6.6.1 Steamfield O&M Costs

A typical steamfield O&M cost is about NZD $20.yr^{-1}.kW^{-1}$ (gross) of steamfield plant capacity, equating to about NZD $400,000.yr^{-1}$ for a 20 MW plant and $1,000,000.yr^{-1}$ for a 50 MW plant.

These figures include fixed costs for operating personnel and both planned and unplanned maintenance on the wells and the fluid collection and disposal systems, together with routine down well measurements as required for typical production field activities.

This O&M figure does not include make-up and replacement well (“M&R”) drilling, testing, and connection that will be incurred at various times during the production life of a project to maintain geothermal fluid and energy supply to the power plant at the level required to maintain full turbine loading. Due allowance therefore needs to be made for the drilling of production and reinjection M&R wells, which at times will substantially exceed other O & M costs.

The numbers of M&R wells required, and the timing for when they will be required, is initially determined by harmonic decline analysis, as discussed in detail in Section 5.2.2 and is then later assessed by detailed numerical simulation studies over the life of the field once production has commenced.

The numbers of makeup wells and the years in which they are required have been determined in detail in the financial modelling undertaken in Section 8. From these data it can be generalised that for a typical 3% harmonic decline in the rate of geothermal production, the number of replacement production wells over a 30 year project life will be around 90% of the number of production wells required at the commencement of power generation (though the variation is from 50% to 150% across the 32 options considered here). It is further assessed that the number of replacement injection wells over 30 years will also be about 90% of the number required at start up (the variation is from 70% to 100% across the 32 options considered here).

The M&R well costs are entered into the cash flow as an expense in the year in which they are drilled (refer to Section 6.9).

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6.6.2 Power Plant O&M Costs

Geothermal power plants typically incur annual O&M costs in the range of about 50 to 100 $NZD.kW^{-1}$. At this level total O&M costs are up to about 1 NZ $cent.kWh^{-1}$.

The following table gives an estimated breakdown for power plant O&M costs in the size range of 20 to 50 MW as considered in this study. These values have been used directly in the financial modelling undertaken in Section 8. Although the variable costs in Table 6-7 are expressed in $NZD.kWh^{-1}$(gross), they are applied in the modelling to the net kWh.

▪ **Table 6-7 Nominal Breakdown of Geothermal Power Plant O&M Costs**

			Gross Capacity Factor	*%*	95%	95%
			Gross Capacity	*MWe*	**20**	**50**
			Gross Generation	*$kW.yr^{-1}$*	166,440,000	416,100,000
Fixed Costs	Labour & Mngt		$NZD.yr^{-1}$		$ 1,250,000	$ 1,800,000
Variable Costs	Materials		$NZD.yr^{-1}$		$ 50,000	$ 150,000
	Planned Maintenance (major overhauls)					
		Cycle period	yr		2	2
		Labour	per cycle		$ 200,000	$ 300,000
		Materials	per cycle		$ 50,000	$ 125,000
	Unplanned Maintenance					
		Labour	$NZD.yr^{-1}$		$ 50,000	$ 75,000
		Materials	$NZD.yr^{-1}$		$ 100,000	$ 200,000
Fixed Costs			$NZD.yr^{-1}$		$ 1,250,000	$ 1,800,000
			$NZD.kWe^{-1}$		$ 60	$ 40
Variable Costs			$NZD.yr^{-1}$		$ 325,000	$ 637,500
			$NZD.kWh^{-1}$		$ 0.0020	$ 0.0015
Total Power Plant O&M Costs		expressed as	$NZD.yr^{-1}$		$ 1,575,000	$ 2,437,500
		expressed as	$NZD.kWh^{-1}$		$ 0.010	$ 0.006
		expressed as	$NZD.kWe^{-1}$		$ 80	$ 50

6.6.3 Total O&M Costs

Combining O&M costs from the three sections above gives the following overall O&M costs from which it can be seen to range from 1.5 to 2.0 NZ cent.kWh^{-1} for 50 and 20 MW developments respectively.

Table 6-8 Total Geothermal Project O&M Costs

	20 MW plant			50 MW Plant		
	$NZD.yr^{-1}$	$NZD.kWh^{-1}$	$NZD.kWe^{-1}$	$NZD.yr^{-1}$	$NZD.kWh^{-1}$	$NZD.kWe^{-1}$
Steam field O&M	$ 600,000	$ 0.004	$ 30	$ 1,500,000	$ 0.004	$ 30
Power Plant O&M	$ 1,600,000	$ 0.010	$ 80	$ 2,400,000	$ 0.006	$ 50
TOTALS	$ 2,200,000	$ 0.014	$ 110	$ 3,900,000	$ 0.010	$ 80

In addition to these fixed and variable costs there are additional planned maintenance costs associated with regular major overhauls which include statutory inspections. These costs are estimated at 150,000 NZD per overhaul for a 20 MW plant and 200,000 NZD for a 50 MW plant. The frequency of such inspections varies from one plant to another but is generally once every three years.

A final cost category related to stocks and costs of consumables has been allowed for at 10% of total O&M costs.

6.7 Commercial Costs

Commercial costs associated with developments also need to be included in costing a geothermal project. These include financing charges (including establishment costs and interest), interest during construction, corporate overhead, legal costs, insurances, and the like. Due allowance needs to be made for these in the financial analysis. These costs are discussed in more detail in Section 8.

6.8 Cost Sensitivities

6.8.1 Sensitivity to Drilling Success

Drilling success is of considerable importance to project development costs and overall economics. If the resource is well understood, and conditions are favourable, drilling success rates of 70% or more may be achieved (including exploration wells), resulting in lower total drilling costs for a given size of project.

In the New Zealand geothermal environment, success rates by private sector developers are generally higher than this due to the considerable Crown legacy in exploration drilling and resource proving which removes much of the well success risk on the private sector (see Section 4 for further discussion on this). For the purposes of this study, the low and high envelope well capacities of 50 and 150 kg.s^{-1} are assumed to be the average including both successful and unsuccessful wells.

6.8.2 Climatic Factors

New Zealand's mild climate is reasonably favourable for:

- obtaining low cooling water temperatures and, hence, high vacuum in the turbine condenser for condensing steam plant, and
- good night time and winter time cooling for ORC power plant but with less efficient summer time cooling.

Given that all new significant geothermal projects, except an expansion at Ngawha, will be in the Taupo Volcanic Zone, site-specific climatic factors will not vary significantly.

6.8.3 Site Specific Factors (Terrain and Access)

Most of New Zealand's geothermal fields are in relatively subdued volcanic terrain, thus they do not require extraordinary effort and expense to build access roads, and undertake extensive ground levelling and earthworks.

6.8.4 Plant Capacity Factor

Electricity delivered at the grid connection point is determined by:

- Plant net capacity – gross capacity less internal power consumption
- Scheduled outages, and
- Unscheduled outages.

Gross capacity is affected by plant degradation (e.g. due to scale build-up or turbine blade erosion). Some of this degradation is recoverable and some is unrecoverable.

Scheduled outages are normally related to maintenance. Geothermal power plants are generally reliable once early experience is gained specific to the resource, steamfield and power plant configuration.

For the purpose of this study the following assumptions have been made and are used in the financial model to determine the electricity stream delivered at the grid connection point:

1.	Internal power consumption	6% of gross capacity for Single and Double Flash 8% of gross capacity for Hybrid 12% of gross capacity for ORC

2.	Recoverable output degradation	1% per year of gross capacity
3.	Unrecoverable output degradation	0.1% per year of gross capacity
4.	Annual unscheduled outages	200 hours
5.	Annual scheduled outages	240 hours
6.	Overhaul cycle	once every three years
7.	Overhaul outage	14 days

The above factors for outages and overhauls lead to a net capacity factor of 91% over the plant life (net capacity factor is the ratio of “net delivered electricity (kWh) over the plant life” to “net capacity at Year 0 (kW) multiplied by total calendar hours over plant life”).

To achieve the above, geothermal energy supply needs to be maintained at or above the normal level of plant consumption. It is thus important to ensure that spare production and reinjection capacity is provided at the outset, and production (and where, because of enthalpy changes, the amount of brine for reinjection does not diminish at the same rate as reinjection capacity may decrease, reinjection capacity) make-up wells should be drilled to provide an adequate buffer of fluid/energy supply.

For this reason, the Makeup & Reinjection (M&R) well drilling schedule built into the financial analysis of project options is setup to maintain at least 10% excess steam reserve over and above full load power plant requirements.

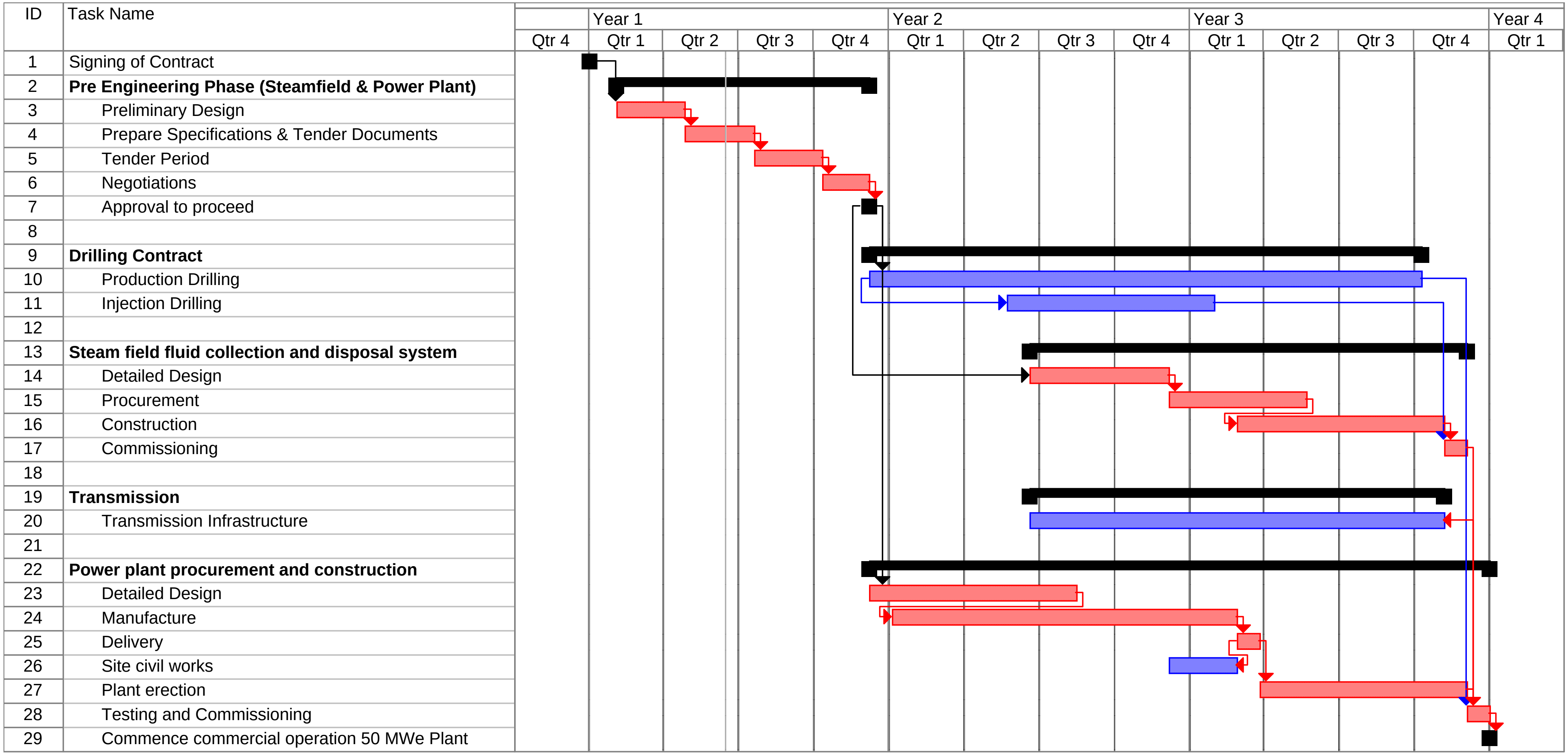
6.9 Timing of Costs

For the purposes of project analysis, the timeline in Figure 6.1 indicates a typical project programme. In terms of cash flow analysis, a project is only certain once consents have been obtained and a satisfactory construction contract has been finalised. Year zero, for project analysis is taken from the approval to proceed. Exploration, geoscience and EPC tender preparation and negotiation costs are assumed to be brought on to the books at year zero despite their earlier expenditure. Time from contract signing to commissioning is assumed to be 24 months. During this period costs are assumed to be normally distributed throughout the construction period, as detailed in the financial model output (Appendix A).

M&R wells are added as previously indicated from the date of commissioning (the start of operational year 1). For accounting purposes these are expensed in the year in which they are drilled.

6.10 Other Cost Information

Further useful discussions on factors affecting cost of geothermal power have been presented by Sanyal (2005) and Hance and Gawell (2005), but we would emphasise that the details in those papers are specific to the USA and these costs are now significantly out of date, having been largely gathered over the period 2000 to 2003. Due account needs to be taken of country specific factors, along with the usual technical and commercial factors. Another relatively current discussion is presented by Quinlivan and Batten (2006).



■ **Figure 6-1 Typical Schedule for a 50 MW Geothermal Power Project**

7. Assessed Capital Costs for Development Scenarios

7.1 Development Costs

Based on the cost data given in Section 6, capital costs have been estimated for the geothermal developments given in the various scenarios presented earlier and these are presented in Tables 7.2 (for high envelope well options) and Table 7.3 (for low envelope well flow options). Some of these data are presented graphically in Figure 7.1 (resource temperature versus capital costs for each development scenario) and Figure 7.2 (resource temperature versus specific capital costs for each development scenario). A zero decommissioning value has been assumed for the purposes of this study – this has negligible net impact on the model outputs at the end a 30 year life. Table 7.1 gives a summary of the capital cost data for each development option, filtered on the basis of mean capital cost.

Table 7-1 Summary Capital Cost Data

				Capital Cost NZD M				Specific Capital Cost NZD.kW^{-1}			
#	Cycle	MW	°C	High Env	Low Env	Mean	±	High Env	Low Env	Mean	±
1,17	SF	50	300	171	205	188	9%	3,400	4,100	3,750	9%
5,21	DF	50	300	188	209	198	5%	3,800	4,200	4,000	5%
9,25	Hybrid	50	300	187	222	204	9%	3,700	4,400	4,050	9%
2,18	SF	50	260	186	243	215	13%	3,700	4,900	4,300	14%
10,26	Hybrid	50	260	197	248	222	12%	3,900	5,000	4,450	12%
6,22	DF	50	260	203	250	227	10%	4,100	5,000	4,550	10%
13,29	ORC	50	300	223	259	241	7%	4,500	5,200	4,850	7%
14,30	ORC	50	260	233	285	259	10%	4,700	5,700	5,200	10%
3,19	SF	20	260	97	118	107	10%	4,800	5,900	5,350	10%
4,20	SF	20	230	97	127	112	14%	4,800	6,300	5,550	14%
7,23	DF	20	260	105	121	113	7%	5,300	6,000	5,650	6%
11,27	Hybrid	20	260	105	125	115	9%	5,300	6,300	5,800	9%
12,28	Hybrid	20	230	105	128	117	10%	5,300	6,400	5,850	9%
15,31	ORC	20	260	107	133	120	11%	5,400	6,600	6,000	10%
8,24	DF	20	230	105	136	121	13%	5,300	6,800	6,050	12%
16,32	ORC	20	230	107	133	120	11%	5,400	6,600	6,000	10%

Table sorted on mean specific capital cost

From these data and figures, plant options can be ranked on the basis of mean capital costs as follows:

300 °C Resource / 50MW plant size

Mean capital cost estimations (and specific capital costs) vary from NZD 188 M (3,750 per kW) for a single flash steam plant to NZD 198 M (4,000 per kW) for a double flash steam plant to NZD 204 M (4,050 per kW) for a hybrid plant and to NZD 241 M (4,850 per kW) for a pure ORC plant. Mean values for the double flash plant and hybrid options are very similar.

260 °C Resource / 50MW plant size

Mean capital cost estimations (and specific capital costs) vary from NZD 215 M (4,300 per kW) for a single flash steam plant to NZD 222 M (4,450 per kW) for a hybrid plant to NZD 227 M (4,550 per kW) for a double flash steam plant and to NZD 264 M (5,300 per kW) for a pure ORC plant. Mean values for the double flash plant and hybrid options are very similar.

260 °C Resource / 20MW plant size

Under these conditions the cost performance ranking is the same as the "300°C Resource / 50MW plant size". Mean capital costs are in the range NZD 107 to 120 M corresponding with mean specific capital costs of NZD 5,350 to 6,000 per kW. Mean values for the double flash plant and hybrid options are only slightly dissimilar.

230 °C Resource / 20MW plant size

Mean capital cost estimations (and specific capital costs) vary from NZD 112 M (5,550 per kW) for a single flash steam plant to NZD 119 M (6,000 per kW) for a hybrid plant to NZD 121 M (6,050 per kW) for a double flash plant and to NZD 131 M (6,500 per kW) for a pure ORC plant.

The increased cost competitiveness of hybrid plant against double flash plant at both 260 and 230 °C resource conditions and 20 MW plant size reflects:

- the increasing specific cost of steam turbines, particularly condensing steam turbines, at smaller unit sizes due to the reduction in manufacturing economies of scale, and
- the increasing specific volume of steam as the source temperature of the geothermal fluid decreases. This increases the physical size of the turbine in order to swallow the required steam flow.

From these observations, it is evident that from the perspective of costs alone and within the level of accuracy of the analysis:

- 300 °C / 50MW plant size:

  Cost of single flash < hybrid = double flash << ORC

- 260°C / 50MW plant size:

  Cost of single flash < hybrid = double flash << ORC

- 260^{o}C / 20MW plant size:
  Cost of single flash < double flash = hybrid < ORC
- 230^{o}C / 20MW plant size:
  Cost of single flash < hybrid = double flash < ORC

Table 7-2 Estimate of Capital Costs for High Envelope Developments

CAPTAL COSTS - HIGH FLOW ENVELOPE	Option	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
	Res T	300	260	260	230	300	260	260	230	300	260	260	230	300	260	260	230
	Cycle	SF	SF	SF	SF	DF	DF	DF	DF	Hybrid	Hybrid	Hybrid	Hybrid	ORC	ORC	ORC	ORC
	MW gross	50	50	20	20	50	50	20	20	50	50	20	20	50	50	20	20
Establishment Costs																	
Permitting	NZ $ M	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Land acquisition	NZ $ M	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Geoscientific / Environmental	NZ $ M	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Well Testing	NZ $ M	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Civil works and Infrastructure	NZ $ M	1.0	1.0	0.5	0.5	1.0	1.0	0.5	0.5	1.0	1.0	0.5	0.5	1.0	1.0	0.5	0.5
Site Operations	NZ $ M	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Pre Feas/ Feas Repors	NZ $ M	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Commerical negotiations	NZ $ M	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
S/T	NZ $ M	3.5	3.5	3.0	3.0	3.5	3.5	3.0	3.0	3.5	3.5	3.0	3.0	3.5	3.5	3.0	3.0
Construction Costs														2550		2710	
Power plant capital cost	NZ$/kW installed	1,900	1,900	2,200	2,200	2,100	2,100	2,450	2,450	2,200	2,200	2,600	2,600	2,700	2,700	2,700	2,700
	NZ$ M	95	95	44	44	105	105	49	49	110	110	52	52	135	135	54	54
Spares*	NZ$ M	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Steamfield costs	NZ$/kW installed	650	650	790	790	770	770	940	940	650	650	790	790	650	650	790	790
	NZ$ M	33	33	16	16	39	39	19	19	33	33	16	16	33	33	16	16
Electrical transmission - 10km	NZ$ M	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Grid connection	NZ$ M	3.0	3.0	2.0	2.0	3.0	3.0	2.0	2.0	3.0	3.0	2.0	2.0	3.0	3.0	2.0	2.0
	NZ$ M	7.0	7.0	6.0	6.0	7.0	7.0	6.0	6.0	7.0	7.0	6.0	6.0	7.0	7.0	6.0	6.0
Switchyard *	NZ$ M	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
S/T	NZ$ M	135	135	66	66	151	151	74	74	150	150	74	74	175	175	76	76
Drilling Costs																	
Rig Mob/Demob	NZ$ M	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Cost per Well	NZ$ M /well	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Production wells	Wells required	2	4	2	2	2	4	2	2	2	3	2	2	3	4	2	2
	NZ$ M	10	21	10	10	10	21	10	10	10	16	10	10	16	21	10	10
Cost per Well	NZ $ M /well	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
Injection wells	Wells required	2	3	2	2	2	3	2	2	2	3	2	2	3	4	2	2
	NZ$ M	8	13	8	8	8	13	8	8	8	13	8	8	13	17	8	8
S/T	NZ$ M	21	36	21	21	21	36	21	21	21	31	21	21	31	40	21	21
Developers Costs																	
Legal	NZ$ M	1.6	1.7	0.9	0.9	1.8	1.9	1.0	1.0	1.7	1.8	1.0	1.0	2.1	2.2	1.0	1.0
Financing	NZ$ M	1.6	1.7	0.9	0.9	1.8	1.9	1.0	1.0	1.7	1.8	1.0	1.0	2.1	2.2	1.0	1.0
Engineering & PM mgt	NZ$ M	8	9	5	5	9	10	5	5	9	9	5	5	10	11	5	5
Others	NZ$ M																
S/T	NZ $ M	11	12	6	6	12	13	7	7	12	13	7	7	15	15	7	7
Total Project Costs	**NZ$ M**	**171**	**186**	**97**	**97**	**188**	**203**	**105**	**105**	**187**	**197**	**105**	**105**	**223**	**233**	**107**	**107**
Ratios	NZD / kW gross	3,400	3,700	4,800	4,800	3,800	4,100	5,300	5,300	3,700	3,900	5,300	5,300	4,500	4,700	5,400	5,400
At USD/NZD 0.70	USD / kW gross	2,400	2,600	3,400	3,400	2,700	2,900	3,700	3,700	2,600	2,700	3,700	3,700	3,200	3,300	3,800	3,800

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■ Table 7-3 Estimate of Capital Costs for Low Envelope Developments

CAPTAL COSTS - LOW FLOW ENVELOPE	Option	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32
	Res T	300	260	260	230	300	260	260	230	300	260	260	230	300	260	260	230
	Cycle	SF	SF	SF	SF	DF	DF	DF	DF	Hybrid	Hybrid	Hybrid	Hybrid	ORC	ORC	ORC	ORC
	MW	50	50	20	20	50	50	20	20	50	50	20	20	50	50	20	20
Establishment Costs																	
Permitting	NZ $ M	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Land acquisition	NZ $ M	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Geoscientific / Environmental	NZ $ M	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Well Testing	NZ $ M	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Civil works and Infrastructure	NZ $ M	1.0	1.0	0.5	0.5	1.0	1.0	0.5	0.5	1.0	1.0	0.5	0.5	1.0	1.0	0.5	0.5
Site Operations	NZ $ M	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Pre Feas/ Feas Repors	NZ $ M	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Commerical negotiations	NZ $ M	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
S/T	NZ $ M	3.5	3.5	3.0	3.0	3.5	3.5	3.0	3.0	3.5	3.5	3.0	3.0	3.5	3.5	3.0	3.0
Construction Costs														2550		2710	
Power plant capital cost	NZ$/kW installed	1,900	1,900	2,200	2,200	2,100	2,100	2,450	2,450	2,200	2,200	2,600	2,600	2,700	2,700	2,700	2,700
	NZ$ M	95	95	44	44	105	105	49	49	110	110	52	52	135	135	54	54
Spares*	NZ$ M	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Steamfield costs	NZ$/kW installed	650	650	790	790	770	770	940	940	650	650	790	650	650	650	790	790
	NZ$ M	33	33	16	16	39	39	19	19	33	33	16	13	33	33	16	16
Electrical transmission - 10km	NZ$ M	4.0	4.0	4.0	3.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Grid connection	NZ$ M	3.0	3.0	2.0	2.0	3.0	3.0	2.0	2.0	3.0	3.0	2.0	2.0	3.0	3.0	2.0	2.0
	NZ$ M	7.0	7.0	6.0	5.0	7.0	7.0	6.0	6.0	7.0	7.0	6.0	6.0	7.0	7.0	6.0	6.0
Switchyard *	NZ$ M	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
S/T	NZ$ M	138	135	66	65	151	151	74	74	150	150	74	71	175	175	76	76
Drilling Costs																	
Rig Mob/Demob	NZ$ M	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Cost per Well	NZ$ M / well	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Production wells	Wells required	6	11	5	6	5	10	4	6	6	9	4	5	7	10	5	5
	NZ$ M	31	57	26	31	26	52	21	31	31	47	21	26	36	52	26	26
Cost Well	NZ $ M / well	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
Injection wells	Wells required	4	7	3	4	3	6	3	4	5	7	4	4	6	8	4	4
	NZ$ M	17	29	13	17	13	25	13	17	21	29	17	17	25	34	17	17
S/T	NZ$ M	51	89	41	51	41	80	36	51	55	79	40	45	64	88	45	45
Developers Costs																	
Legal	NZ$ M	1.9	2.3	1.1	1.2	2.0	2.3	1.1	1.3	2.1	2.3	1.2	1.2	2.4	2.7	1.2	1.2
Financing	NZ$ M	1.9	2.3	1.1	1.2	2.0	2.3	1.1	1.3	2.1	2.3	1.2	1.2	2.4	2.7	1.2	1.2
Engineering & PM mgt	NZ$ M	9	11	6	6	10	12	6	6	10	12	6	6	12	13	6	6
Others	NZ$ M																
S/T	NZ $ M	13	16	8	8	14	16	8	9	15	16	8	9	17	19	9	9
Total Project Costs	**NZ$ M**	**205**	**243**	**118**	**127**	**209**	**250**	**121**	**136**	**222**	**248**	**125**	**128**	**259**	**285**	**133**	**133**
Ratios	NZD / kW	4,100	4,900	5,900	6,300	4,200	5,000	6,000	6,800	4,400	5,000	6,300	6,400	5,200	5,700	6,600	6,600
At USD/NZD 0.70	USD / kW	2,900	3,400	4,100	4,400	2,900	3,500	4,200	4,800	3,100	3,500	4,400	4,500	3,600	4,000	4,600	4,600

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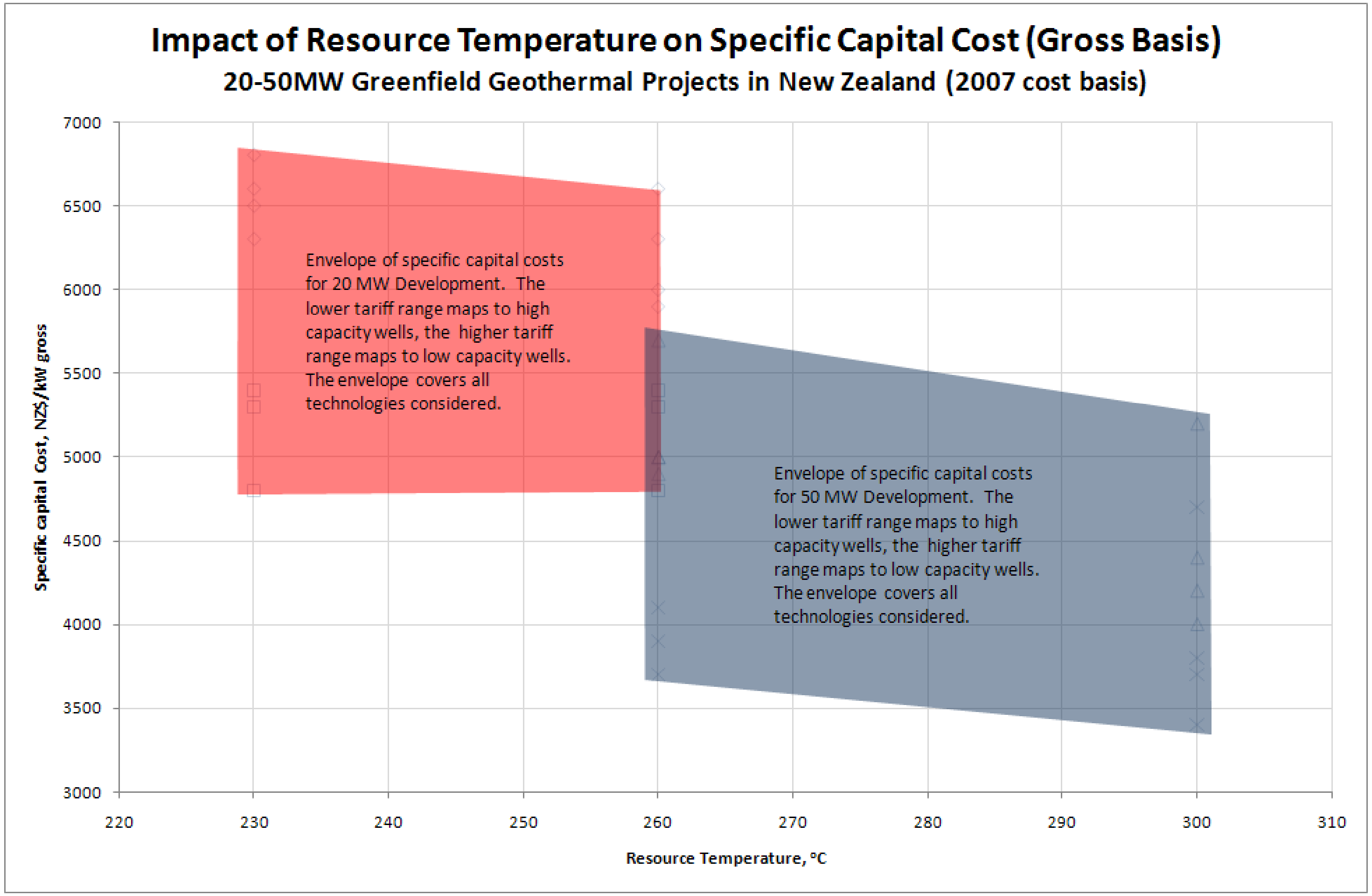


▪ **Figure 7-1 Plot of Specific Capital Costs vs. Reservoir Temperature for Different Types and Sizes of Plant**

It is noteworthy that the double flash plant option is comparable with the cost performance of the hybrid options at all reservoir conditions, but is always higher in cost than the single flash options. Reasons for this lesser performance against the single flash option include the following:

- The double flash options involve greater complexity and cost in steamfield civil works, mechanical works and instrumentation as shown in Table 6.2 and also within the power plant as evident in Table 6.4. These penalize the cost performance of this option
- at lower resource temperatures, both the first and second stage flash stages are less constrained by silica supersaturation issues and the geothermal water can be flashed to lower end pressures than can be achieved for fluids from higher reservoir temperatures, and
- in this analysis, the second stage flash pressure has been set at the limit where silica saturation in the waste brine reaches 1.30 (i.e. is 30% over saturated with dissolved silica and quite susceptible to forming scale deposits). It is recognized that a more aggressive approach could be taken to gaining additional second stage flash steam through further reduction of flash pressure, but this is at the risk of increasing potential for silica deposition and involves further cost and complexity of chemical treatment and control measures.

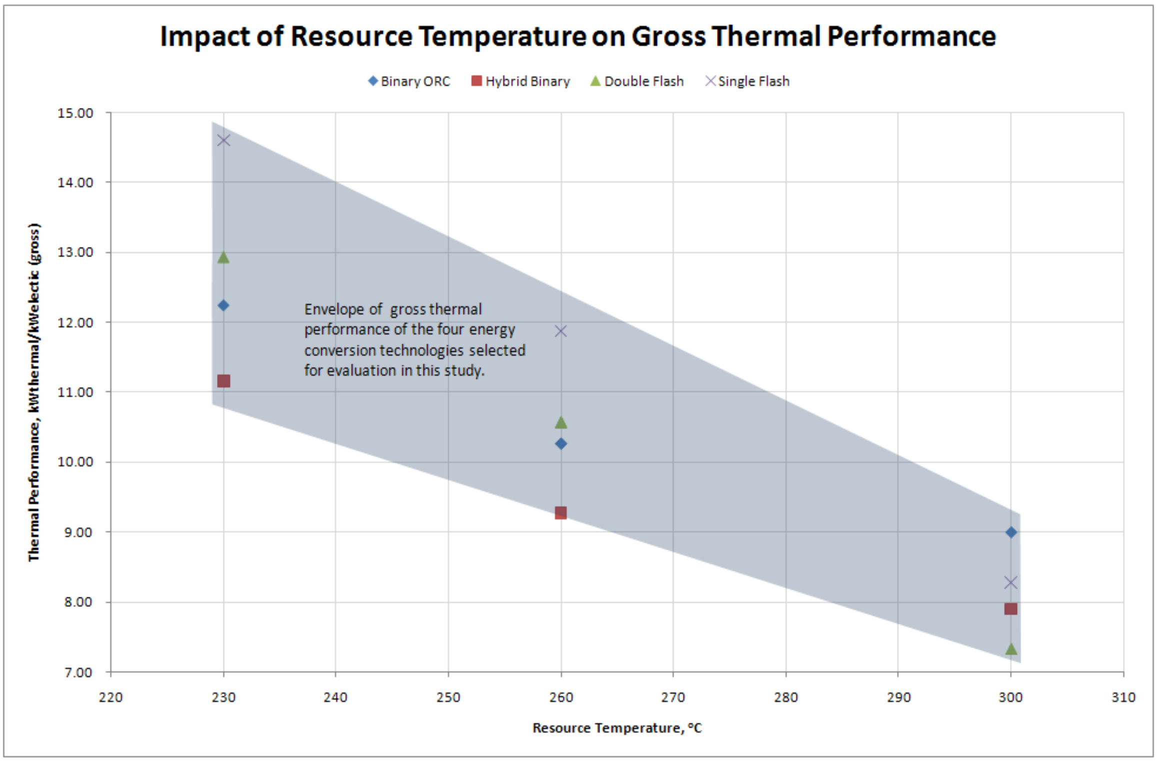
It is also noteworthy that ORC plant options have not performed very well in this cost analysis. This is due to the relatively high specific cost of this technology (see Table 6.5). The hybrid steam + binary option reduces specific cost considerably by placing a relatively low cost non-condensing turbine, with relatively high power output, upstream of the higher cost ORC equipment and this achieves a much better specific capital cost performance.

Pure ORC plant is better suited to lower resource temperatures than analysed here and it is apparent in the data above that the ORC cost performance is improving as the steam flash down to 230 ^{o}C reduces. If this analysis was carried out at lower temperatures it is expected that the ORC option would become the preferred cost option at about 200 ^{o}C and below. Adopting the use of well pumping would also change the economics.

7.2 Plant Performance

The above review of plant performance is limited to cost performance – i.e. a consideration of the power than can be generated from each option compared with the cost of the equipment. It is instructive to then also consider the thermal performance of these plant options without regard to cost.

This can be readily undertaken by using the data in Table 7.1 to obtain the specific heat rate for geothermal fluid that needs to be input into each development option per MW of gross electrical output achieved. A graph prepared on this basis is shown in Figure 7.3.



▪ **Figure 7-2 Plot of Thermal Performance versus Resource Temperature and Plant Size**[20]

These performance rankings are quite different to the cost rankings obtained in Section 7.1. They show for all reservoir conditions the hybrid and double flash options outperforming single flash due to the increased energy recovery from both steam and brine.

The issue then for a geothermal development is the cost of each technology with respect to the power generation that can be achieved and it is for this reason that the specific cost of electricity (in NZD per kWh delivered) becomes such an important consideration for evaluating the commercial performance of one technology against another.

7.3 Offshore vs. Local Costs

In Section 6, nominal assessments were made of the percentage split of costs into local costs and overseas costs for each development component. The impact on overall project cost of these individual costs are examined in Table 7.4 in which these percentage splits have been applied to

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[20] A useful reference point on this figure is the design value for the Mokai I hybrid geothermal power plant of 7.7 MWth / MW, but which is actually achieving 6.4 MWth.MW^{-1} (Menzies et. al. 2001).

the development cost estimates for Option 18 as built up in Table 7.2. This option was chosen being a typical project configuration of a 50 MW plant on a 260 °C resource.

From this computation it is assessed that local and overseas cost are both about 50% of the total project cost.

- **Table 7-4 Assessed Split of Development Costs into Local / Overseas Components**

	Option 18. Low envelope. 260°C. 50 MW. SF.			
	Assessed Local Content	Total Cost	Local Cost	Foreign Cost
	%	NZD M	NZD M	NZD M
Establishment Cost	90%	3.5	3.2	0.4
Drilling Cost	40%	89.0	35.6	53.4
Steamfield Cost	80%	33.0	26.4	6.6
Power Plant Cost	25%	95.0	23.8	71.3
Transmission Interconnection Cost	40%	7.0	2.8	4.2
Developer Cost	90%	16.0	14.4	1.6
Total		243.5	106.1	137.4
			44%	56%

In the event that the turbine, generator and electrical equipment are to be sourced from Japan then approximately 75% of the foreign currency requirement should be indexed to the Japanese Yen, otherwise it should be indexed in full against the USD.

7.4 Recent Changes and Future Trends in Power Sector Costs

Between 2003 and 2007 the global economy exhibited very large fluctuations in the prices of both fossil fuels and commodities.

7.4.1 Impact of fossil fuel price increases[21]

Very large increases in fossil fuel prices during 2006 and 2007 had two significant impacts on the geothermal industry:

- they provided considerable stimulation to the oil and gas exploration industry which put considerable pressure on the availability of drilling rigs, drilling personnel, drilling materials, wellheads valves and casing in both the oil and gas and geothermal industries
- they led to significant increases in drilling rental rates and the cost of drilling materials. In a New Zealand context, rental rates for large drilling rigs were around NZD 45,000 per day in

[21] Written in mid 2007.

2006, whereas in 2007 the rate for a large 3500 m capacity drilling rig with one million pound hook load capacity was around NZD 55,000 per day

The drilling costs estimated in Section 6.3 were best estimates at current 2007 costs but it needs to be noted that these would need to be updated if cost reliance was required. Such impacts of fossil fuel price increases are negative for geothermal energy, but of more significance is the effective raising of the cost of gas with its direct impact on wholesale electricity price. Increases in drilling costs could be more than offset by increased wholesale electricity prices which would tend to stimulate geothermal power generation development.

7.4.2 Impact of increase in commodity prices[22]

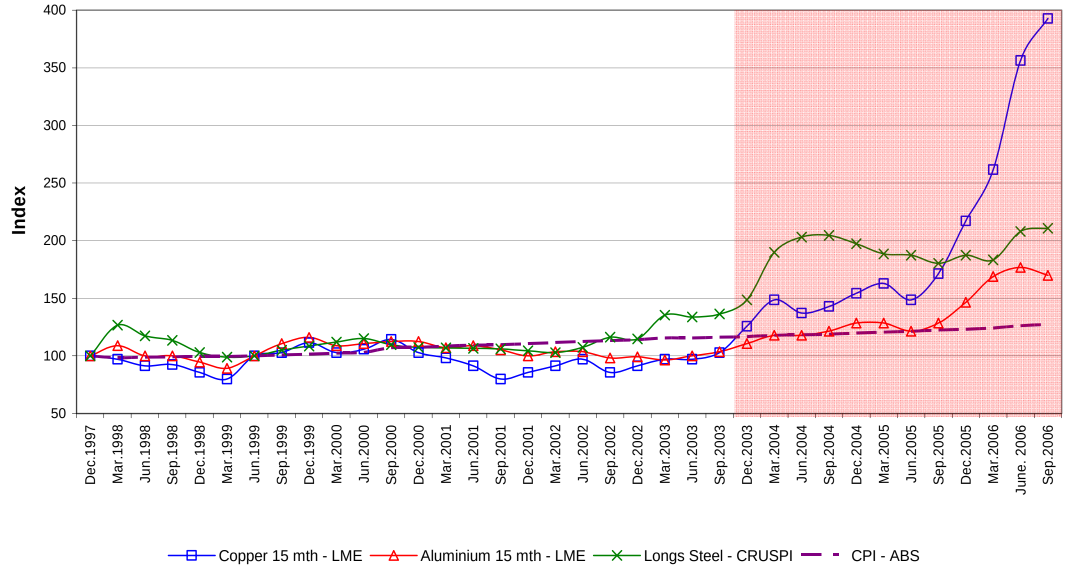
The pace of infrastructure developments in China over recent years has led to a huge increase in prices of metal commodities. Metals of direct relevance to the power industry are shown in Figure 7.5 and these increased fourfold between 2003 and 2007.

SKM is aware of the following impacts of the current global economic conditions on power generation projects in Australasia:

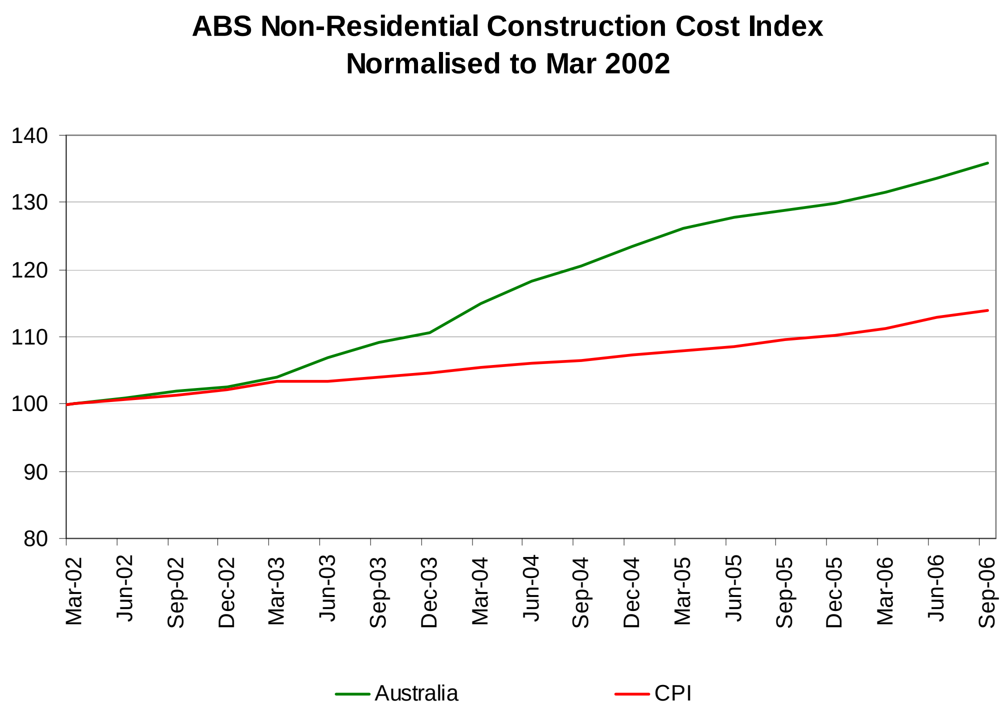
- In the transmission sector:
  - between 2003 and 2007 transmission line costs went up by 18 % compared with CPI of 11%
  - power transformer costs went up by 20% between 2005 and 2007 due to substantial increases in core steel prices for the NZ market, and international freight costs
- In the generation sector, during 2006 alone:
  - there was a 3 to 6% increase in the cost of gas turbines
  - a 6 to 12% increase steam turbines and generator costs, and
  - a 5% increase for balance of plant
  - Based on material price influence for turbine, generator and balance of plant, overall plant investment costs are increasing by more than 5% pa, compared with CPI around 3%
- In the Australian construction sector, which the New Zealand sector follows, actual costs between 2003 and 2007 increased at a rate 3 times that predicted by CPI.

Regulators favour the use of CPI as an escalation index in that it is simple, recognized and readily audited. However experience in 2003 to 2006 cited here suggested that:

- CPI is not a reliable indicator of future costs, and
- Volatility in commodity prices is resulting in significant % increases.



- **Figure 7-3 Increases in Prices of Commodities Impacting on the Power Sector**



- **Figure 7-4 Increases in Australian Construction Costs**

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[22] Written in mid 2007.

Within this regime of future price uncertainty, SKM formulated the following as a guide to future possible cost trends 2006 to 2008 in the power sector (Table 7.4).

Of particular relevance to geothermal developments were the predictions for 10 to 20% increases in establishment costs, civil works and generators, over this period.

- **Table 7-5 SKM Estimates of Future Price Increases in the Australasian Power Industry**

Category	RBA Projected Aust CPI 2006 – 2008*	SKM Projected Cost Escalation
Power transformers	5.27%	16 - 20%
Substation bays	5.27%	6 - 8%
Establishment / Civil's	5.27%	10 - 15%
Transmission OH lines	5.27%	8 -11%
Cables	5.27%	30 - 50%
General construction	5.27%	12 - 18%
Generation	5.27%	10 – 20%

While these projected price movements might have occurred, they would have affected a wide range of technologies. The unit costs calculated in the following pages are based on 2007 costs and so compare with other 2007 costs being quoted by various sources. The accuracy of the 2007 projections in the above table has not been tested in the final version of this study.

7.4.3 Update on impact of changes in commodity prices[23]

Commodity prices continued to increase throughout 2007 and peaked in mid-2008. Since that time there has been very marked drop in many prices, but there is now evidence of another upward swing in commodity prices. This is illustrated by the following table and figures.

- **Table 7-6 Commodity price movements since 2004**

Commodity	Price in mid-2004	Price in mid-2006	Peak price in 2008	Price in early 2009	Price in Oct 2009	Units
Copper	3000	8000	9000	3000	6000	USD/tonne
Aluminium	1500	2250	2750	1100	1700	USD/tonne
Iron ore (Hamersley)	..	62	135	98	98	USD/tonne

[23] Written in late 2009.

- **Figure 7-5 Copper prices 2004-2009**

- **Figure 7-6 Aluminium prices 2004-2009**

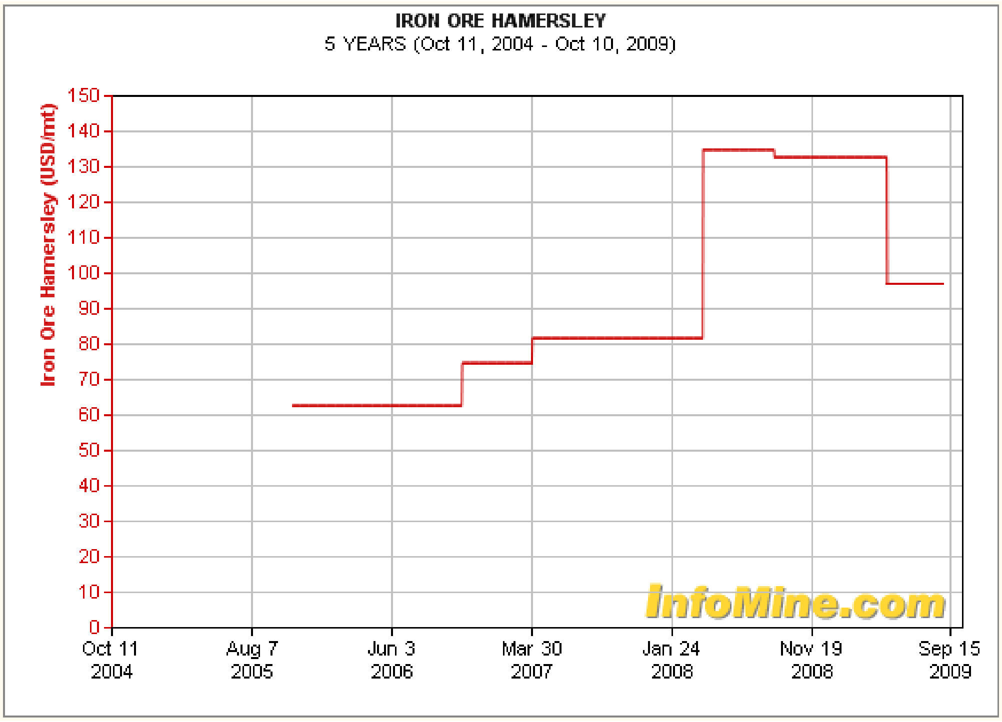


Figure 7-7 Iron Ore price movements since early 2005

These commodities are used in geothermal developments and fluctuations in their prices influence the cost of geothermal developments.

Similar rises and then falls have been experienced over the period 2002 to 2009 in fossil fuel prices and stock markets around the world. These fluctuations have occurred in parallel with a Global Financial Crisis, the outcome of which is uncertain at the current time (October 2009).

It is therefore difficult to predict when and how these falls from the highs of 2008, and the recent partial recoveries will be reflected in market prices for piping and OEM supplied equipment, although it is expected they will continue to exert pressure on prices that continued to rise through the middle of 2008.

8. Financial Modelling

A financial model has been applied to the 32 development options presented in the previous sections. The capital costs for the each project option as estimated in Section 7 have been input to this model together with the operations and maintenance costs (O&M) developed in Section 6.8, assessed over the operating life of the project which is assumed to be 30 years.

The key outputs from the model runs are estimates of the required "electricity tariff" for each project development option for a variety of financial assumptions of which corporate tax rate, depreciation, inflation and equity content are the most important.

These tariff values are equivalent to the year 0 selling prices required to achieve the financial hurdle After Tax Internal Rate of Return (IRR) assumed in the model.

8.1 Model Structure

The financial model used for this study is a well documented geothermal industry model developed by SKM. A detailed description of the model and its capabilities has been published by Randle (2005).

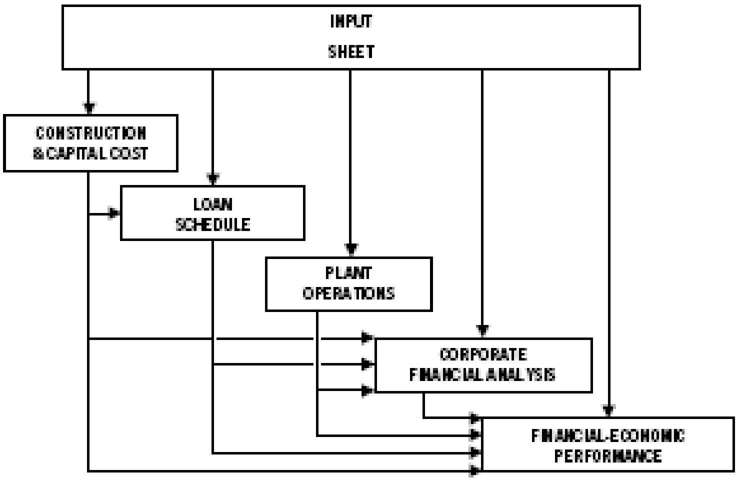
The model is based on a number of interconnected worksheets in a workbook. The overall structure and interrelationships of these are shown in Table 8-1. The main outputs from the model are contained in a Corporate Financial Analysis Worksheet and a Financial-Economic worksheet. The Corporate Financial Analysis Sheet generates a number of standard financial reports.

Based mainly on information contained in the Corporate Financial Analysis Sheet, the Financial-Economic Performance Sheet determines a number of standard through-life and annual parameters that are commonly used to determine the financial strength and ongoing wellbeing of the project. This sheet presents the electricity tariff sold in both current (subject to inflation) and real (excluding inflation) terms, a number of other net present value (NPV) and internal rate of return (IRR) calculations, and also includes a number of other financial parameters.

The real electricity tariff is calculated as the PV of the gross income stream from electricity sales (uninflated), divided by the PV of the steam of electricity delivered at the node, both PVs at the defined Discount Rate. Note that the assumed Discount Rate has no impact on this ratio (whereas it does have an impact on the ratio of PV of the through life cost steam (inflated or uninflated), divided by the PV of the steam of electricity delivered at the node (commonly referred to as the levelised cost of generation)).

The Real Project IRR is calculated as the discount rate at which the Present Value (PV) of the Net Cash Flow stream (zero inflation) equals the PV of the initial Capital Expenditure stream (zero inflation).

The Real Project NPV is the PV of the after tax zero inflation free cash flow.



▪ **Figure 8-1 Structure of the SKM Financial Model**

8.2 Model Inputs and Assumptions

An example data input worksheet (for NZGA Option # 1) is given in Appendix A.1. This shows in detail the model inputs and values used. These inputs are discussed below.

8.2.1 Capital Costs

Capital cost inputs for the financial modeling are obtained from Tables 7.1 and 7.2.

8.2.2 Operations and Maintenance Costs

O&M cost inputs for the financial modeling are obtained from Section 6.6.

8.2.3 Electricity delivered at the grid transmission node

This is determined from the net capacity delivered at the node and the number of hours that the plant is operating. The net capacity is affected by capacity degradation, both recoverable and unrecoverable. The number of hours is affected by planned and unplanned outages and plant overhauls. Net capacity is determined from gross capacity less plant auxiliary loads.

8.2.4 Debt Funding

Most geothermal power projects are financed with a high level of debt funding on a project finance basis. However, in order to make the results of this study directly comparable with those for other power generation technologies, 100% equity funding is assumed. It is therefore assumed that there will be no interest costs incurred during construction, prior to the project being commissioned and generating a revenue stream.

8.2.5 Inflation

An inflation rate of 0% per annum has been applied to all costs in the models, and to the tariff.

8.2.6 Cost of Carbon

No allowance has been made for a cost of (or credit for) carbon emissions (or carbon reductions) associated with the production of geothermal electricity.

8.2.7 Royalties

No allowance has been made for the payment of royalties associated with the extraction of geothermal fluids or the production of geothermal electricity.

8.2.8 Corporate Tax

A corporate tax rate of 30% has been assumed in all the models. In practice it is likely that a developer will have a corporate tax rate lower than this across its development and power plant operations.

8.2.9 Depreciation

A simplified straight line depreciation rate of 8% per annum is used.

8.2.10 Discount Rate

A discount rate of 10% per annum has been used in all models and this is used to determine the required real Year 0 electricity tariff for a 30 year project life.

8.2.11 Target Internal Rate of Return

A target project IRR of 10% per annum (real) is used to determine the initial real selling price (“cost”/”tariff”) of electricity in Year 0 terms. The Year 0 price of electricity is varied until this IRR is achieved.

8.3 Modelling Results

8.3.1 Model Outputs

Typical Projected Balance Sheets and Projected Cash Flow Statements are presented in Appendix A.2. These typical outputs are presented for Option #1.

The Input/Output Sheet in Appendix A.1 also summarizes the following outputs:

1.	Cumulative Generation Revenue	$
2.	Cumulative Interest income	$
3.	Cumulative Project Income	$
4.	Cumulative Total Operating Costs	$
5.	Cumulative Profit before tax	$
6.	Cumulative Total tax	$
7.	Cumulative Profit after tax	$
8.	Cumulative Net Cash Flow	$
9.	Project NPV	$
10.	Internal Rate of Return	%
11.	Year 0 Electricity Tariff - Real	$ / MWh
12.	Year 0 Electricity Tariff - Current	$ / MWh

(11 and 12 differ only if a non-zero inflation rate is assumed).

Table 8-1 presents the results of the financial modeling for all options considered.

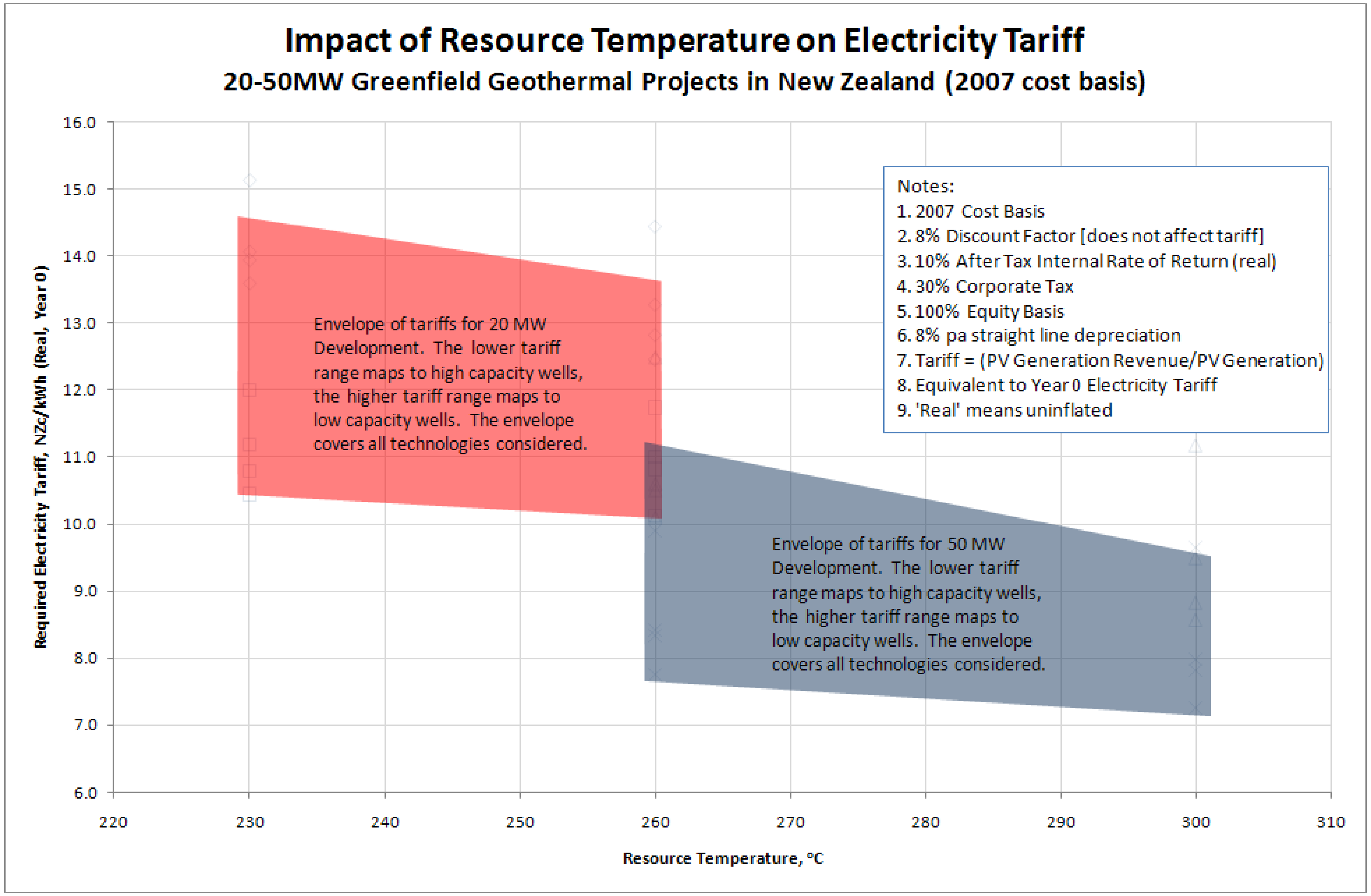
8.3.2 Electricity Tariff

Figure 8-2 presents the range of required Year 0 electricity tariffs associated with the 32 cases evaluated for this study.

SKM

Table 8-1 Summary of Financial Model Outputs

Option	Cycle	Flow Band	Plant Size	Resource Temperature	Capital Cost	Specific Capital Cost	Year 0 Tariff (real)	NPV
		$kg.s^{-1}$	MW	°C	NZD M (2007)	$NZD.kW^{-1}$ (2007)	$NZc.kWh^{-1}$	NZD M
1	SF	150	50	300	170	3400	7.3	29
2	SF	150	50	260	190	3700	7.8	31
5	DF	150	50	300	190	3800	7.8	32
6	DF	150	50	260	200	4100	8.3	34
9	Hybrid	150	50	300	190	3700	8.0	32
10	Hybrid	150	50	260	200	3900	8.4	33
13	ORC	150	50	300	220	4500	9.6	37
14	ORC	150	50	260	230	4700	9.9	37
17	SF	50	50	300	210	4100	8.6	34
18	SF	50	50	260	240	4900	10.1	39
21	DF	50	50	300	210	4200	8.8	35
22	DF	50	50	260	250	5000	10.5	42
25	Hybrid	50	50	300	220	4400	9.5	37
26	Hybrid	50	50	260	250	5000	10.6	42
29	ORC	50	50	300	260	5200	11.0	43
30	ORC	50	50	260	280	5700	12.5	48
3	SF	150	20	260	100	4800	10.1	16
4	SF	150	20	230	100	4800	10.5	16
7	DF	150	20	260	110	5300	10.8	17
8	DF	150	20	230	110	5300	10.8	17
11	Hybrid	150	20	260	110	5300	11.0	17
12	Hybrid	150	20	230	110	5300	11.2	17
15	ORC	150	20	260	110	5400	11.7	18
16	ORC	150	20	230	110	5400	12.0	18
19	SF	50	20	260	120	5900	12.5	20
20	SF	50	20	230	130	6300	13.6	21
23	DF	50	20	260	120	6000	12.8	20
24	DF	50	20	230	140	6800	13.9	22
27	Hybrid	50	20	260	130	6300	13.3	21
28	Hybrid	50	20	230	130	6400	14.1	22
31	ORC	50	20	260	130	6600	14.4	22
32	ORC	50	20	230	130	6600	15.1	23



■ **Figure 8-2 Required Year 0 Tariff (real) vs Resource Temperature**

9. Summary and Conclusions

There are a number of general conclusions that can be made from this study with regard to the applicability of the various power cycle types for various reservoir conditions, cost efficiencies and thermal performance, as follows:

- at each reservoir temperature, the required real electricity tariff of single flash, double flash and hybrid cycle plants of both 20 and 50 MW capacity are within 0.8 NZc.kWh^{-1} of one another for the high and low well productivity envelopes, but the ORC options are approximately 0.8 to 1.8 NZc.kWh^{-1} above this range
- at reservoir temperatures around 230 ^{o}C and high well productivity, the gap between the ORC option and the other three options still exists, but has reduced to approximately 0.7 NZc.kWh^{-1}.

From the modelling studies undertaken herein, and importantly, based on the assumptions made for reservoir and well flow characteristics and the various commercial parameters used in the financial modelling (notably interest rate, loan term, debt to equity, discount rate and inflation rate), it is concluded that the geothermal developments in New Zealand in 2007 could have been undertaken within the following envelopes for capital costs and Year 0 electricity tariffs:

- *300 ^{o}C / 50MW plant size*:
  - cost of single flash plant < hybrid = double flash << ORC
  - mean capital cost estimations (and specific capital costs) vary from NZD 188 M (3,750 per kW) for a single flash steam plant to NZD 198 M (4,000 per kW) for a double flash steam plant to NZD 204 M (4,050 per kW) for a hybrid plant and to NZD 241 M (4,850 per kW) for a standalone ORC plant. Mean values for the double flash plant and hybrid options are very similar
  - Year 0 required electricity tariff. High productivity: 7.3 to 8.0 NZc.kWh^{-1} for single flash, double flash and hybrid, 9.6 NZc.kWh^{-1} for ORC. Low productivity: 8.5 to 9.5 NZc.kWh^{-1} for single flash, double flash and hybrid, 11.1 NZc.kWh^{-1} for ORC.
- *260 ^{o}C / 50MW plant size*:
  - cost of single flash < hybrid = double flash << ORC
  - mean capital cost estimations (and specific capital costs) vary from NZD 215 M (4,300 per kW) for a single flash steam plant to NZD 222 M (4,450 per kW) for a hybrid plant to NZD 227 M (4,550 per kW) for a double flash steam plant and to NZD 264 M (5,300 per kW) for a standalone ORC plant. Mean values for the double flash plant and hybrid options are very similar

  - Year 0 required electricity tariff. . High productivity: 7.7 to 8.5 $NZc.kWh^{-1}$ for single flash, double flash and hybrid, 9.9 $NZc.kWh^{-1}$ for ORC. Low productivity: 10.1 to 10.5 $NZc.kWh^{-1}$ for single flash, double flash and hybrid, 12.5 $NZc.kWh^{-1}$ for ORC.
- *260 ^oC / 20MW plant size:*
  - Cost of single flash < double flash = hybrid < ORC
  - Under these conditions the cost performance ranking is the same as the "300^{o}C Resource / 50MW plant size". Mean capital costs are in the range NZD 107 to 120 M corresponding with mean specific capital costs of NZD 5,350 to 6,000 per kW. Mean values for the double flash plant and hybrid options are only slightly dissimilar
  - Year 0 required electricity tariff. High productivity: 10.1 to 11.0 $NZc.kWh^{-1}$ for single flash, double flash and hybrid, 11.7 $NZc.kWh^{-1}$ for ORC. Low productivity: 12.5 to 13.4 $NZc.kWh^{-1}$ for single flash, double flash and hybrid, 14.4 $NZc.kWh^{-1}$ for ORC.
- *230 ^oC / 20MW plant size:*
  - Cost of single flash < hybrid = double flash < ORC
  - Mean capital cost estimations (and specific capital costs) vary from NZD 112 M (5,550 per kW) for a single flash steam plant to NZD 119 M (6,000 per kW) for a hybrid plant to NZD 121 M (6,050 per kW) for a double flash plant and to NZD 131 M (6,500 per kW) for a standalone ORC plant
  - Year 0 required electricity tariff. High productivity: 10.5 to 11.2 $NZc.kWh^{-1}$ for single flash, double flash and hybrid, 12.0 $NZc.kWh^{-1}$ for ORC. Low productivity: 13.6 to 14.1 $NZc.kWh^{-1}$ for single flash, double flash and hybrid, 15.1 $NZc.kWh^{-1}$ for ORC.

Double flash plant were found in all of the analyses to have higher specific capital costs than the single flash steam options, in spite of double flash plant having good thermal efficiency at all of the reservoir temperatures examined. This is due to the greater complexity and thus cost required within the steamfield and power plant to accommodate the second stage steam flash separators and piping / instrumentation and the additional cost for a fitting out a turbine with two steam inlets. It is these additional costs which penalize the double flash option relative to the single flash options.

The analysis undertaken here for the double flash option is relatively conservative. A more aggressive approach could be taken through reducing the second stage flash pressure further to generate a greater steam flow from the second stage flash step. This would improve the cost performance of this option, however, this would be at the risk of silica super saturation in the waste brine exceeding 130% with increased potential for scale deposition even with chemical treatment.

The costs developed here relate to a 2007 base and have been internally calibrated against costs incurred at New Zealand geothermal developments, of which there were (and are) a number in progress at the present time, and several overseas geothermal projects currently in progress.

Due to the state of the global economy, which over the period 2003 to 2007 was dominated by strongly rising commodity and metals prices, and high fossil fuel costs, there was appreciable upwards pressure on geothermal development costs and they were expected to rise further for the foreseeable future while the China boom continued. It was anticipated that there could have been similar cost increases across a wide range of non-geothermal development options also.

The New Zealand and geothermal community had for quite some years been comfortable with the view that Greenfield geothermal power could be developed in New Zealand at a cost of about NZD 3,000.kW^{-1}. The results of the study show that this was no longer the case in 2007 and under even the best possible development scenario where wells were drilled into a 300^{o}C reservoir, and with very high flow rates of 150 $kg.s^{-1}$, specific capital costs of at least 3,500 NZD.kW^{-1} for development of a 50 MW plant would have been incurred. Under more typical geothermal resource conditions for New Zealand, of 260°C reservoir temperatures and with well flow rates as for less than 100 $kg.s^{-1}$, development costs in the order of 4,000 to 4,500 NZD.kW^{-1} were anticipated.

As noted, for several years prior to 2007, geothermal development costs rose steadily in line with global market commodity and equipment price rises. These rises continued until the middle of 2008 when the current global financial crisis occurred and commodity prices fell back to 2003 levels. It is not certain that there is enough market data available yet to determine what is currently happening to geothermal power plant, steamfield and well costs to be able to compare current (2009) costs with the 2007 estimates used in this study.

Nevertheless, when this situation clears it would be useful to update this report to a current (2009) basis, and to include brownfield cases in the range 50 – 100 MW.

A typical 50 MW project schedule is given in Section 6 which shows that 24 months is required to complete a project from the time that consents and approval to proceed are obtained (and EPC contracts are ready to execute, subject only to approval to proceed). Given the ongoing rising cost structure of the geothermal industry over the past few years, developers need to be aware of the potential for significant cost increases to occur during the course of a 24 month project.

The local and overseas cost components of a geothermal power development in New Zealand have been examined from which it is concluded that approximately 56% of the capital cost for a new project would be required for foreign purchases and about 50% of this foreign cost would be required for procurement of items relating to the power plant. This allocation of funds should then be indexed against the currency of the county in which that expenditure is likely to be incurred - most likely as either Yen or USD.

This study did not look at greenfield developments greater than 50 MWe. The main reason is that a greenfield developer would most likely not be able to attract the funds required for a larger development until some experience with the particular resource was gathered and the risks associated with a larger development were able to be well quantified. Furthermore a greenfield development of over 50 MWe may struggle to obtain resource consents in New Zealand, given the conservatism of regulatory authorities and their preference for staged developments, for the same reasons.

This contrasts with the current situation in New Zealand where large second stage developments of medium to high temperature resources are occurring at brownfield sites (100 MWe at Kawerau and 132 MWe at Nga Awa Purua (Rotokawa)). This implies that the anticipated returns on these investments within the current electricity market in New Zealand are attractive – and developers are on record as stating that "Geothermal is the lowest cost source of new generation for New Zealand[24]".

[24] Baldwin, D. (2008). op. cit.

10. References

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Appendix A Example of Financial Model Input & Output

SKM

A.1 Input

Financial Analysis - NZGA Cost Study Options

Input Data Sheet

Key to worksheet colours:

Inputs	(yellow)
Calculated Cells	(light blue)

POWER PLANT CAPACITY 50 MWe (gross)

Key Outputs copied from the other worksheets:			
Energy Tariff in year 0	Cents / kWh	7.3	in Year 0 (thereafter inflated, i
Generation Revenue	$	$814,652,527	Current value, gross income
Interest income	$	$0	Current value, depends on Inter
Project Income	$	$814,652,527	Current value
Total Operating Costs	$	$308,888,143	Current value, O&M (incl replace
Profit before tax	$	$505,764,384	Current value
Total tax	$	$151,729,315	Current value
Profit after tax	$	$354,035,069	Current value
Nett Cash Flow	$	$524,592,069	Current value
Free Cash Flow NPV	$	$28,886,127	This is Nominal (No inflation adjustment - ie, if an inflation allowance is assumed, this calc is based on the inflated costs and revenue streams)
Internal Rate of Return	IRR	10.0%	The discount rate at which PV(Nett Cash Flow [incl. interest received]) equals PV(Capit Includes the impact of the assumed inflation (ie nominal). Wl
Levellised Tariff - Real	$ / MWh	73	Impact of inflation is removed (so its real) =PV(Income from electricity sales, real dollars)/PV(Electricity delivered at the n
Levellised Tariff - Current	$ / MWh	73	No inflation re-adjustment (ie it includes inflation) =PV(Income from electricity sales, current dollars)/PV(Electricity delivered at th
Net Generation	MWh	11,230,996	
Levellised Net Generation	MWh	3,641,303	

Date		12-Oct-09
Version		NZGA Option # 1
Status		Final
	High Envelope	300C
		50MWe
		SF
		7-Oct-09

CAPTAL COSTS

Establishment Costs				
Permitting		0.2	$ M	6%
Land acquisition		0.6	$ M	17%
Geoscientific / Environmental		0.5	$ M	14%
Well Testing		0.5	$ M	14%
Civil works and Infrastructure		1.0	$ M	29%
Site Operations		0.5	$ M	14%
Pre Feas/ Feas Repors		0.2	$ M	6%
Commerical negotiations		-	$ M	0%
	Sub Total 1	**3.5**	$ M	**2%**
Construction Costs				
Power plant capital cost		1,900	$/kW installed (gross)	
		95	$ M	71%
Spares		-	$ M	0%
Steamfield costs		650	$/kW installed (gross)	
		33	$ M	24%
Electrical transmission - 20km		4.0	$ M	
transformer		3.0	$ M	
		7.0	$ M	5%
Switchyard / Sub station		-	$ M	0%
	Sub Total 2	**135**	$ M	**79%**
Drilling Costs				
Rig DeMobe		2.6	$ M	12%
Cost per Well*		5.2	$ M /well	
Production wells		2.0	wells required	
		10	$ M	49%
Cost Well*		4.2	$ M /well	
Injection wells		2.0	wells required	
		8.4	$ M	39%
	Sub Total 3	**21**	$ M	**13%**
		159.4		
Developers Costs				
Legal		1.6	$ M	1%
Financing		1.6	$ M	1%
Engineering & PM mgt		8.0	$ M	5%
		-	$ M	0.0%
	Sub Total 4	**11**	$ M	**7%**
Total Project Costs		**171**	**$ M**	**100%**
	SCC	**3.4**	**$M / MWe**	

OPERATIONAL DATA

Operating Parameters			
Auxiliary Load		6.0%	of gross
Plant Nominal Net Output		47	MW (net)
Recoverable Output Degradation		1.0%	per year
Non-Recoverable Output Degradation		0.10%	per year
Scheduled maintenance		240	hrs/year
Unscheduled outages		200	hrs/year
1st Overhaul (after commissioning)		1.5	years
Overhaul Cycle		3	years
Overhaul Outage		14	Days
Dispatch Factor		98%	% [This Factor Not Used]
Operating Costs			
Power Plant O&M (fixed)		40.00	NZ$ /kW gross year
Power Plant O&M (variable)		0.0015	NZ$ /kWh
Overhaul Cost		200,000	NZ$/Overhaul
Steamfield O&M (total)		20.00	NZ$/kW gross year
Consumables		10%	O&M Costs
Well Replacement Rate		autodecline	wells
	every	autodecline	years
Well Replacement Cost		5,200,000	NZ$/well
Share of Head Office Costs		0	NZ$/year
Project Timing			
Project Start Date		1-Jan-08	Calendar Date
Start Construction		3	Months After Project Start
Construction Start Date		1-Apr-08	
Construction Duration		21	Months after Constr. Start
Construction Cost Deviation		2.5	
First Power Available		21	Months after Constr. Start
First Power Available		2.00	Years After Project Start
Project Duration		30	Years After First Power
Project Start year		1-Jan-10	
Project Completion Date		24-Dec-39	
Carbon Credits			
Displaced Carbon		0.50	tonne CO2/MWh
Credit value		0.00	NZ $/tonne CO2
Royalties			
Local Govt	Either :	0.0%	of Tariff
		0.00	NZc per kWh (nett generation)
	or :	0.0%	of net profit BEFORE tax

ECONOMIC DATA

Energy Tariff			
Energy Tariff in year 0		7.25	NZc per kWh
Tariff Adjustment		0.000%	year from commissioning
Economic Inputs			
Discount Rate		8.00%	per annum
Inflation		0.00%	per annum
Corporate Finance Inputs:			
Corporate Income Tax Rate		30.0%	
Average Depreciation		8.0%	
Insurance (on Original Capital Value)		0.0%	
Interest on Bank Account		0%	
Dividend Payout (% of After Tax Profit)		0%	
Target Debt/Equity		0%	Debt
		100%	Equity
Equity Inputs:			
Incoming Asset Value *		0	NZ$
Equity Input Pro-Rata to Debt		Yes	Yes/No
Then New Equity Required		170,557,000	NZ$
Or Equity Input Uniformly Spread		No	
Equity Input Spread Over First		3	Months
Equity Input		0	NZ$
Debt Inputs:			
Loan Interest		8.00%	
Loan Drawdown	As required	No	Yes/No
	At project start	Yes	Yes/No
	At construct start	No	
Loan Period in years		20.0	years
Repayment Moratorium		0.0	years
Loan Required		0	NZ$
Working Capital			
Debtors		0	Days Revenue
Stocks		0	Days O&M
Creditors		0	Days O&M

*** Note**
Incoming Asset Value

Sinclair Knight Merz.

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A.2 Output

Projected Balance Sheets

Year Ended			2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Fixed Assets																																			
At Cost		$	104,470,091	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	0
Accumulated Depreciation		$	0	0	8,357,607	22,002,167	35,646,727	49,291,287	62,935,847	76,580,407	90,224,967	103,869,527	117,514,087	131,158,647	144,803,207	158,447,767	167,913,524	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	0
Total Fixed Assets		$	104,470,091	170,557,000	162,199,393	148,554,833	134,910,273	121,265,713	107,621,153	93,976,593	80,332,033	66,687,473	53,042,913	39,398,353	25,753,793	12,109,233	2,643,476	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Current Assets																																			
Debtors		$	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Stocks		$	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bank Balances		$	0	0	19,219,297	40,047,455	59,801,888	80,921,766	101,435,063	121,259,380	142,320,041	162,775,127	182,544,592	203,546,035	223,942,911	243,657,524	264,599,748	283,684,772	290,644,208	310,253,847	326,440,933	341,952,474	358,682,894	374,811,770	390,268,459	406,939,661	423,010,327	438,412,163	455,024,147	471,036,602	486,383,587	502,936,353	518,890,597	529,982,729	0
Total Current Assets		$	0	0	19,219,297	40,047,455	59,801,888	80,921,766	101,435,063	121,259,380	142,320,041	162,775,127	182,544,592	203,546,035	223,942,911	243,657,524	264,599,748	283,684,772	290,644,208	310,253,847	326,440,933	341,952,474	358,682,894	374,811,770	390,268,459	406,939,661	423,010,327	438,412,163	455,024,147	471,036,602	486,383,587	502,936,353	518,890,597	529,982,729	0
Total Assets			**104,470,091**	**170,557,000**	**181,418,689**	**188,602,287**	**194,712,160**	**202,187,479**	**209,056,216**	**215,235,973**	**222,652,074**	**229,462,600**	**235,587,505**	**242,944,388**	**249,696,703**	**255,766,756**	**267,243,225**	**283,684,772**	**290,644,208**	**310,253,847**	**326,440,933**	**341,952,474**	**358,682,894**	**374,811,770**	**390,268,459**	**406,939,661**	**423,010,327**	**438,412,163**	**455,024,147**	**471,036,602**	**486,383,587**	**502,936,353**	**518,890,597**	**529,982,729**	**0**
Current Liabilities																																			
Creditors	*0*	$	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Debt Repayment Due	*0*	$	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Taxation	*151,729,315*	$	0	0	3,258,507	3,132,631	2,772,751	3,074,421	2,982,947	2,748,811	3,049,474	2,958,000	2,724,872	3,024,526	2,933,053	2,700,932	4,253,220	6,208,430	3,950,360	7,067,999	6,976,526	6,746,420	7,043,052	6,951,578	6,722,480	7,018,105	6,926,631	6,698,540	6,993,157	6,901,684	6,674,600	6,968,210	6,876,736	5,390,660	0
Dividends Payable	*0*	$	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Current Liabilities		$	0	0	3,258,507	3,132,631	2,772,751	3,074,421	2,982,947	2,748,811	3,049,474	2,958,000	2,724,872	3,024,526	2,933,053	2,700,932	4,253,220	6,208,430	3,950,360	7,067,999	6,976,526	6,746,420	7,043,052	6,951,578	6,722,480	7,018,105	6,926,631	6,698,540	6,993,157	6,901,684	6,674,600	6,968,210	6,876,736	5,390,660	0
Net Current Assets		$	0	0	15,960,790	36,914,823	57,029,136	77,847,345	98,452,116	118,510,569	139,270,567	159,817,127	179,819,721	200,521,509	221,009,858	240,956,592	260,346,528	277,476,342	286,693,848	303,185,847	319,464,407	335,206,054	351,639,842	367,860,192	383,545,979	399,921,557	416,083,696	431,713,623	448,030,990	464,134,919	479,708,986	495,968,143	512,013,861	524,592,069	0
Total Net Assets		$	104,470,091	170,557,000	178,160,182	185,469,656	191,939,409	199,113,058	206,073,268	212,487,162	219,602,600	226,504,600	232,862,634	239,919,861	246,763,651	253,065,825	262,990,005	277,476,342	286,693,848	303,185,847	319,464,407	335,206,054	351,639,842	367,860,192	383,545,979	399,921,557	416,083,696	431,713,623	448,030,990	464,134,919	479,708,986	495,968,143	512,013,861	524,592,069	0
Represented By:																																			
Shareholders' Funds																																			
Share Capital		$	104,470,091	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	170,557,000	0
Revenue Reserves		$	0	0	7,603,182	14,912,656	21,382,409	28,556,058	35,516,268	41,930,162	49,045,600	55,947,600	62,305,634	69,362,861	76,206,651	82,508,825	92,433,005	106,919,342	116,136,848	132,628,847	148,907,407	164,649,054	181,082,842	197,303,192	212,988,979	229,364,557	245,526,696	261,156,623	277,473,990	293,577,919	309,151,986	325,411,143	341,456,861	354,035,069	0
Shareholders' Funds		$	104,470,091	170,557,000	178,160,182	185,469,656	191,939,409	199,113,058	206,073,268	212,487,162	219,602,600	226,504,600	232,862,634	239,919,861	246,763,651	253,065,825	262,990,005	277,476,342	286,693,848	303,185,847	319,464,407	335,206,054	351,639,842	367,860,192	383,545,979	399,921,557	416,083,696	431,713,623	448,030,990	464,134,919	479,708,986	495,968,143	512,013,861	524,592,069	0
Long Term Debt	*0*	$	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Liabilities + Shareholder Equity			**104,470,091**	**170,557,000**	**181,418,689**	**188,602,287**	**194,712,160**	**202,187,479**	**209,056,216**	**215,235,973**	**222,652,074**	**229,462,600**	**235,587,505**	**242,944,388**	**249,696,703**	**255,766,756**	**267,243,225**	**283,684,772**	**290,644,208**	**310,253,847**	**326,440,933**	**341,952,474**	**358,682,894**	**374,811,770**	**390,268,459**	**406,939,661**	**423,010,327**	**438,412,163**	**455,024,147**	**471,036,602**	**486,383,587**	**502,936,353**	**518,890,597**	**529,982,729**	**0**
Capital Employed		$	104,470,091	170,557,000	178,160,182	185,469,656	191,939,409	199,113,058	206,073,268	212,487,162	219,602,600	226,504,600	232,862,634	239,919,861	246,763,651	253,065,825	262,990,005	277,476,342	286,693,848	303,185,847	319,464,407	335,206,054	351,639,842	367,860,192	383,545,979	399,921,557	416,083,696	431,713,623	448,030,990	464,134,919	479,708,986	495,968,143	512,013,861	524,592,069	0

Projected Cash Flow Statements

Year Ended			2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Operations																																			
Operating Profit		$	0	0	10,861,689	10,442,105	9,242,504	10,248,070	9,943,158	9,162,705	10,164,912	9,860,000	9,082,905	10,081,754	9,776,842	9,003,106	14,177,400	20,694,768	13,167,866	23,559,998	23,255,086	22,488,067	23,476,840	23,171,928	22,408,267	23,393,683	23,088,770	22,328,467	23,310,525	23,005,612	22,248,668	23,227,367	22,922,454	17,968,868	0
Depreciation		$	0	0	8,357,607	13,644,560	13,644,560	13,644,560	13,644,560	13,644,560	13,644,560	13,644,560	13,644,560	13,644,560	13,644,560	13,644,560	9,465,756	2,643,476	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Stocks		$	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Debtors		$	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Creditors		$	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cash Flow from Operations		$	0	0	19,219,297	24,086,665	22,887,064	23,892,630	23,587,718	22,807,265	23,809,472	23,504,560	22,727,465	23,726,314	23,421,402	22,647,666	23,643,156	23,338,244	13,167,866	23,559,998	23,255,086	22,488,067	23,476,840	23,171,928	22,408,267	23,393,683	23,088,770	22,328,467	23,310,525	23,005,612	22,248,668	23,227,367	22,922,454	17,968,868	0
Taxation Paid	*-151,729,315*	$	0	0	0	-3,258,507	-3,132,631	-2,772,751	-3,074,421	-2,982,947	-2,748,811	-3,049,474	-2,958,000	-2,724,872	-3,024,526	-2,933,053	-2,700,932	-4,253,220	-6,208,430	-3,950,360	-7,067,999	-6,976,526	-6,746,420	-7,043,052	-6,951,578	-6,722,480	-7,018,105	-6,926,631	-6,698,540	-6,993,157	-6,901,684	-6,674,600	-6,968,210	-6,876,736	-5,390,660
Capital Expenditure		$	-104,470,091	-66,086,909	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Financing Activities																																			
Interest Expense	*0*	$	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Income	*0*	$	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Loans Received	*0*	$	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Loans Repaid	*0*	$	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Equity Injections	*170,557,000*	$	104,470,091	66,086,909	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dividends Paid	*0*	$	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cash Flow from Financing Activities		$	104,470,091	66,086,909	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Cash Flow	*524,592,069*	$	0	0	19,219,297	20,828,158	19,754,433	21,119,879	20,513,297	19,824,318	21,060,661	20,455,086	19,769,465	21,001,443	20,396,876	19,714,613	20,942,224	19,085,024	6,959,436	19,609,638	16,187,087	15,511,541	16,730,420	16,128,876	15,456,688	16,671,202	16,070,666	15,401,836	16,611,984	16,012,455	15,346,984	16,552,766	15,954,244	11,092,132	-5,390,660
Cash Balance		$	0	0	19,219,297	40,047,455	59,801,888	80,921,766	101,435,063	121,259,380	142,320,041	162,775,127	182,544,592	203,546,035	223,942,911	243,657,524	264,599,748	283,684,772	290,644,208	310,253,847	326,440,933	341,952,474	358,682,894	374,811,770	390,268,459	406,939,661	423,010,327	438,412,163	455,024,147	471,036,602	486,383,587	502,936,353	518,890,597	529,982,729	0

			Debt	Equity	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
DSCR																																					
CF available for DS (revs -. opex - change in debtors/creditors - tax)						0	15,960,790	20,954,033	20,114,313	20,818,209	20,604,770	20,058,453	20,759,998	20,546,560	20,002,594	20,701,788	20,488,349	19,946,734	19,389,936	17,129,814	9,217,506	16,491,999	16,278,560	15,741,647	16,433,788	16,220,350	15,685,787	16,375,578	16,162,139	15,629,927	16,317,367	16,103,929	15,574,067	16,259,157	16,045,718	12,578,208	0
Debt Service						0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DSCR						**no DS**	**no DS**	**no DS**	**no DS**	**no DS**	**no DS**	**no DS**	**no DS**	**no DS**	**no DS**	**no DS**	**no DS**	**no DS**	**no DS**	**no DS**	**no DS**	**no DS**	**no DS**	**no DS**	**no DS**	**no DS**	**no DS**	**no DS**	**no DS**	**no DS**	**no DS**	**no DS**	**no DS**	**no DS**	**no DS**	**no DS**	**no DS**
IRR on Free Cash	10.0%	Ungeared	0%	100%	-104,470,091	-66,086,909	19,219,297	20,828,158	19,754,433	21,119,879	20,513,297	19,824,318	21,060,661	20,455,086	19,769,465	21,001,443	20,396,876	19,714,613	20,942,224	19,085,024	6,959,436	19,609,638	16,187,087	15,511,541	16,730,420	16,128,876	15,456,688	16,671,202	16,070,666	15,401,836	16,611,984	16,012,455	15,346,984	16,552,766	15,954,244	11,092,132	-5,390,660
	32.7%	Geared	70%	30.0%	-31,341,027	-19,826,073	19,219,297	20,828,158	19,754,433	21,119,879	20,513,297	19,824,318	21,060,661	20,455,086	19,769,465	21,001,443	20,396,876	19,714,613	20,942,224	19,085,024	6,959,436	19,609,638	16,187,087	15,511,541	16,730,420	16,128,876	15,456,688	16,671,202	16,070,666	15,401,836	16,611,984	16,012,455	15,346,984	16,552,766	15,954,244	11,092,132	-5,390,660

Appendix B Basic Principles of the Various Power Generation Cycles Employed in the Geothermal Industry

B.1 Steam Rankine Cycle Plants

The steam Rankine cycle (steam turbine) has historically been the conventional technology used worldwide for most geothermal generation, particularly from the higher enthalpy resources that have been the most attractive to develop. The technology is similar to the steam Rankine cycle used in thermal power plants except that the steam comes from the geothermal reservoir, rather than a boiler, and is at significantly lower temperatures and pressures.

B.1.1 Back-pressure steam turbine plant

Back-pressure (or atmospheric exhaust without a condenser) steam turbine plant is simple, inexpensive and quick to install. It is very wasteful of steam, however, with a steam consumption at least twice that for condensing plant at typical inlet pressures. Where steam cost is high or where steam supply is constrained, it is not likely to be considered as a long term solution.

B.1.2 Single pressure, condensing steam plant

This power cycle uses a single stage separation of the geothermal two phase fluid, resulting in a single steam admission pressure at the condensing steam turbine. The turbine exhausts into a condenser at a pressure of typically less than 0.15 bara, in order to increase the power output of the turbine. The actual exhaust pressure chosen will usually be determined through an economic optimisation process balancing the increased output at lower condenser pressures against the increased size and cost of the heat rejection system associated with discarding the heat of condensation of the steam.

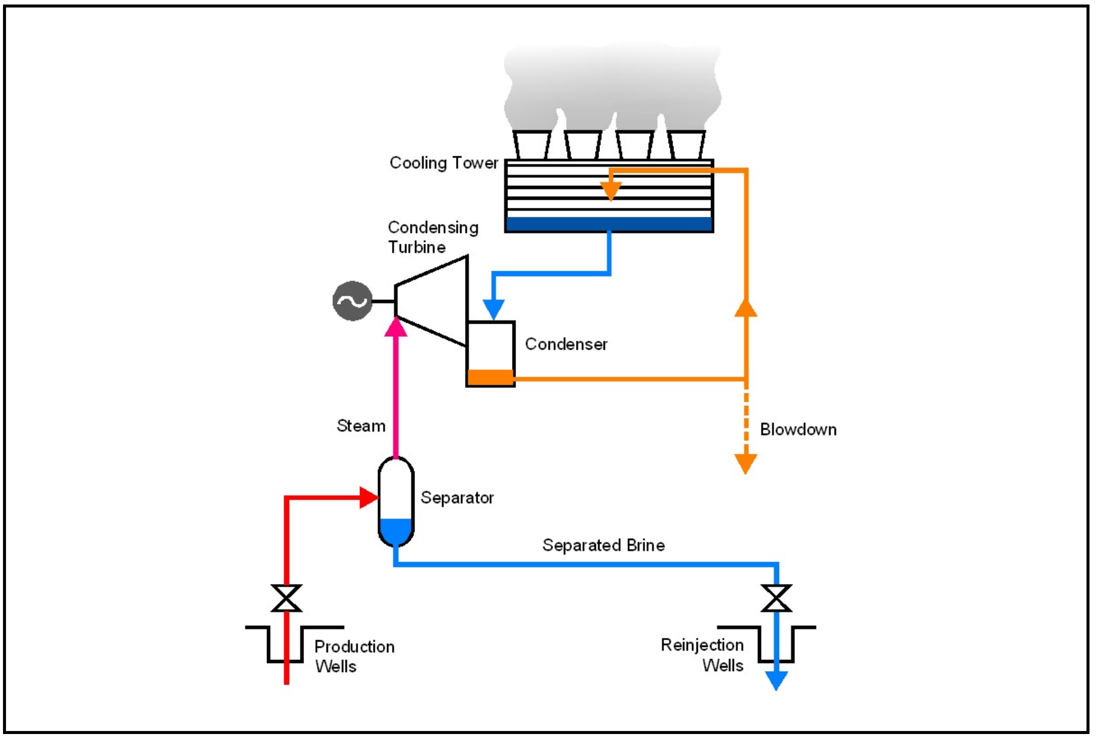
Both “surface condensers” and “direct contact condensers” are used in the geothermal industry. The choice of which type depends largely on the hydrogen sulphide content of the steam and constraints on the discharge of hydrogen sulphide to atmosphere.

Direct contact condensers are more common. Cooling water is sprayed into the condenser in direct contact with the low pressure steam exhausting from the turbine. The mixture of cooling water and steam condensate is removed from the condenser hotwell using “can” pumps, which pump the fluid to a cooling tower. After the water is cooled, it is drawn into the condenser under vacuum to repeat the cycle. Because steam condensate is continually added to the cooling water circuit, and the rate of evaporation is less than the steam flow, the plant is a net producer of steam condensate. This means that, apart from the initial fill of water, the cooling water volume continually increases and the excess must be removed as ‘blow down’. The blow down is normally disposed of to a condensate reinjection well as it commonly contains some contaminants which would potentially impact on the environment if it is disposed of to surface waters.

In a surface condenser the steam is condensed through indirect contact with a cooling fluid. The steam condensate usually joins the circulating cooling water when evaporative cooling towers are used in order to avoid the need for make-up water to replace the evaporation loss in the cooling tower. It is also possible to keep the steam condensate separate from the cooling water, and to use an alternative heat rejection system. This could be air cooling in which case the cooling water is contained within a closed system. It could also be an evaporative cooling tower, but make-up water would then be required to replace evaporative losses as mentioned above, although the steam condensate can also provide this makeup even though it is initially kept separate from the cooling water in the surface condenser. Neither of these heat rejection options is common.

A schematic diagram of a single flash steam turbine power cycle is show in Figure B-1. Key features of the design are:

1) Single steam admission pressure
2) Direct contact condenser and mechanical induced draft wet cooling tower, and
3) Hybrid non-condensable gas (NCG) removal system (first (and sometimes second) stage steam jet ejectors with last stage liquid ring vacuum pumps).

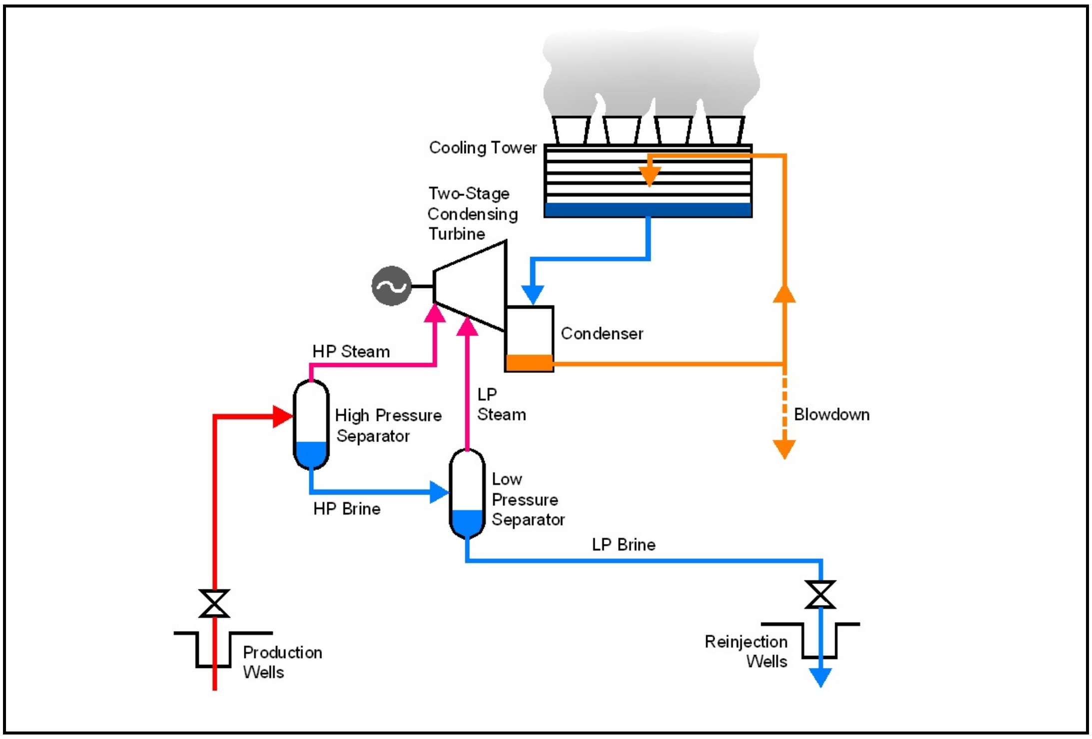


■ **Figure B-1 Single pressure (single flash), condensing steam turbine plant**

B.1.3 Double pressure, condensing steam plant

This is similar to a single pressure condensing steam turbine, but uses two stage separation of the geothermal fluids, resulting in two steam admission pressures at the turbine. The first separation pressure will be higher than for single flash, leaving a greater proportion of first flash liquid. This liquid is then flashed at a lower pressure (much lower than for single flash) and the resultant steam is separated by second stage separation. This type of plant is generally used when the resource can produce medium enthalpy fluids at relatively high wellhead pressures. This enables the primary flash to be undertaken at relatively high pressure, providing steam at high enthalpy to the turbine, with the secondary flash permitting additional steam to be produced from the fluid separated in the primary separator. Very occasionally triple flash systems are used (such as at Nga Awa Purua). There are not many examples of double flash systems world-wide, but they have been used successfully for more than fifty years. The technology is well understood and it involves only an additional steam inlet part way down the steam turbine, for which there are many non-geothermal examples world-wide.

A schematic diagram of a double flash steam turbine power cycle is show in Figure B-2. The key point to note beyond those already noted for single flash condensing steam turbine cycle, is that the turbine has two steam admission pressures.



▪ **Figure B-2 Double pressure (double flash), condensing steam turbine plant**

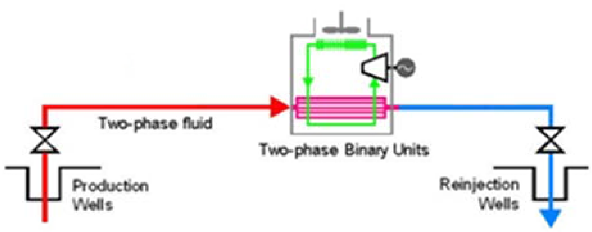
B.2 Organic Rankine Cycles with/without Steam Cycle Option

ORC cycle plant can more effectively use the heat from a lower temperature geothermal fluid. This has allowed economical exploitation of lower enthalpy resources, generally at a higher cost than for a condensing steam plant on a higher enthalpy resource (although the economics are changing as bigger unit sizes are developed for ORC plants).

B.2.1 Organic Rankine Cycle (ORC) without Steam Cycle Option

An organic Rankine cycle (ORC) power plant, which is also known as a “binary cycle” plant, makes use of a low boiling point hydrocarbon, or other organic fluid, as the “working” or “motive” fluid for the turbine, rather than using steam. The particular hydrocarbon is optimally selected based on comparison of heat source temperature and motive fluid properties. In geothermal applications iso- or n-pentane are typically used, although there are also some plants using iso-butane. Compared to the conventional steam cycle, the lower boiling point and higher molecular weight of the hydrocarbon fluid allows for a more compact equipment design than is possible with steam at lower operating temperatures. It is also possible to use refrigerants, organic compounds or a mixture of hydrocarbons as the working fluid for thermodynamic or safety reasons, although this is not often done in practice.

ORC plants have successfully operated on heat source fluids down to 100°C, or even slightly lower. The working fluid operates in a contained, closed-loop cycle and is completely segregated from the heat source fluid. There are several possible variants of the cycle, in terms of heat exchange configuration, turbine configuration etc, which may be selected as appropriate to the temperature and physical state(s) of heat source fluid. The simplest type of ORC power plant is presented in Figure B-3. This is commonly used when the enthalpy is low and the plant size is small or the wells do not discharge at a high pressure (and therefore not at high temperature). This type of plant is typically used in low temperature developments overseas where pumping from the production wells is required because the wells do not flow artesian.



- **Figure B-3 Binary cycle (organic Rankine cycle) power plant, without separation of steam (if any) and brine**

The working fluid absorbs heat from a heat source, in this case the hot geothermal fluid, via one or more heat exchangers, usually shell-and-tube type. This heat causes the working fluid to evaporate, producing the high-pressure vapour that is then expanded through a turbine-generator producing power. Two working fluid heat exchangers are normally used for improved thermodynamic performance – a recuperator for initial heating of the working fluid, using turbine exhaust vapour, followed by the vaporiser. The high-pressure working fluid vapour passes through a liquid separator located on top or downstream of the vaporiser, prior to flowing into the turbine. The separator is required to remove entrained liquid droplets to prevent their impingement on the turbine blades.

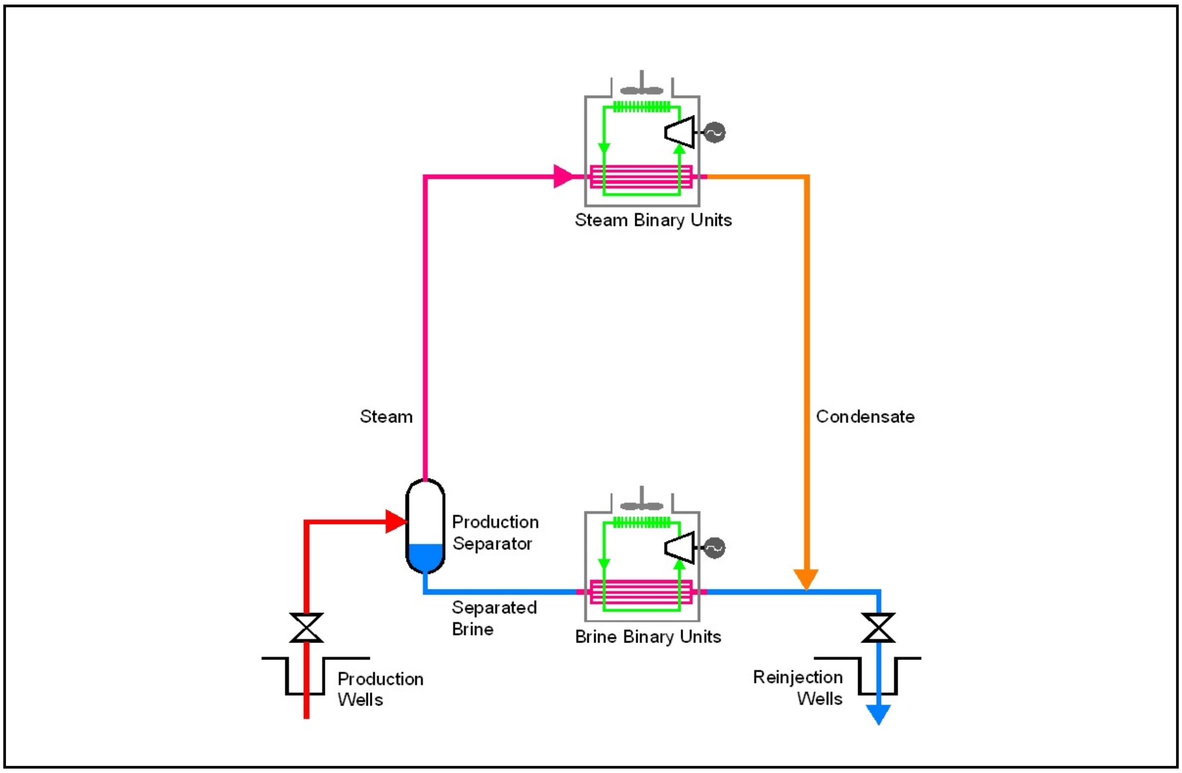
The low pressure turbine exhaust vapour is cooled in the recuperator and then condensed, using either air-cooled heat exchangers ("fin-fan heat exchangers"), or a water-cooled condenser. Air cooling is frequently the only option in locations with limited water supplies, although the motive fluid outlet temperature is then limited by the prevailing ambient dry-bulb, rather than wet-bulb, temperature. This increase in "sink temperature" reduces the overall thermodynamic efficiency of the power cycle (because wet-bulb temperature is always lower than dry-bulb temperature, except when air is 100% saturated with moisture in which condition the temperatures are the same).

The liquid working fluid is pumped at high pressure from the condenser and returned to the recuperator where residual sensible heat in the low-pressure turbine exhaust stream is used for initial preheating of the cooled liquid from the condenser. For more complex ORC plant, where increased cycle efficiency is required, one or more additional heat exchangers may be included in the cycle, as pre-heaters and recuperators between the ORC fluid pump and the vaporiser. The decision to incorporate additional heat exchangers into the cycle usually depends on the temperature range between the available heat source and sink temperatures.

Generally when the plant size is not small and/or the wells discharge at a sufficiently high pressure (and therefore high temperature) the steam and brine phases are used separately (refer to Figure B-4) as each component has a different temperature profile. The brine exhibits a sensible heat transfer temperature profile, whereas steam condensation is practically isothermal. The ORC heat exchangers are designed for the particular heat transfer duty (which includes the temperature profile). By virtue of the complete segregation of the working fluid from the heat source fluid, the ORC cycle also finds application at geothermal fields where the geothermal fluids would be difficult to handle in a conventional steam turbine (e.g. fluid that is particularly corrosive or with a high non-condensable gas content).

Heat rejection is necessary from the ORC fluid as the energy extraction devices (turbines) cannot extract all the energy supplied to the ORC fluid from the geothermal fluid. This heat rejection occurs by indirect contact with another cooling fluid, generally air as mentioned above, but sometimes water if adequate water supplies are available. Because of this indirect heat rejection, none of the geothermal fluid is evaporated. This means that all of the geothermal fluid must be disposed of, either to surface streams or (almost always because of environmental considerations, and often because there may be a positive reservoir pressure enhancement by so doing) by reinjection into the geothermal reservoir. However, this also means that additional reinjection wells may be required, so both the cost of these wells and the potential longevity of the resource (and reduction in make-up production well requirements) should be considered in any comprehensive resource-wide economic assessment. During the early stages of reservoir exploitation the geothermal reservoir is generally not able to be modelled to a degree of accuracy that will give certainty as to whether enhanced reinjection will be to the benefit or the detriment of the resource.

For the purpose of this study the additional well requirements associated with reinjection of that part of any steam condensate which is not evaporated in a cooling system and discharged to atmosphere will not be included in any comparison between power plant options. However, the cost of any such additional wells will be added to the capital cost of the power plant cycle subsequently selected from the comparison.



- **Figure B-4 Binary cycle (organic Rankine cycle) power plant, using both steam and separated geothermal brine**

Individual unit capacities are generally up to 10 MW (gross). This unit size has been successfully used by Ormat, and is representative of a number of purpose-engineered ORC units in service or under development (e.g. Steamboat, Nevada, USA; Berlin, El Salvador).

Key points to note are:

(i) Single steam admission pressure to the plant, but separate streams of steam and brine are used (when the well characteristics and the economics favour this)

(ii) Use of preheaters and recuperators to maximise thermal energy recovered

(iii) Use of air cooled condensers, but water cooling could also be applied; the selection of cooling method would be optimised for cost and performance, and

(iv) Multiple units are used (due to maximum unit size of about 10-15 MW).

B.2.2 Organic Rankine Cycle (ORC) with Steam Cycle Option

This power cycle was developed by Ormat and is referred to by Ormat as a geothermal combined cycle. It is a hybrid cycle that is essentially the same cycle as that depicted in Figure B-4 but with the addition of a back-pressure steam turbine to make more efficient use of higher pressure and temperature steam if this is available. The back-pressure steam turbine is complemented by ORC units fed with low pressure steam discharged from the turbine, and ORC units fed by high temperature brine. If the same working fluid is used for the low pressure steam ORC units and the brine units, the brine units will operate with higher organic-side pressures (due to higher temperature). A simplified schematic diagram of a typical hybrid cycle power plant is presented in Figure B-5.

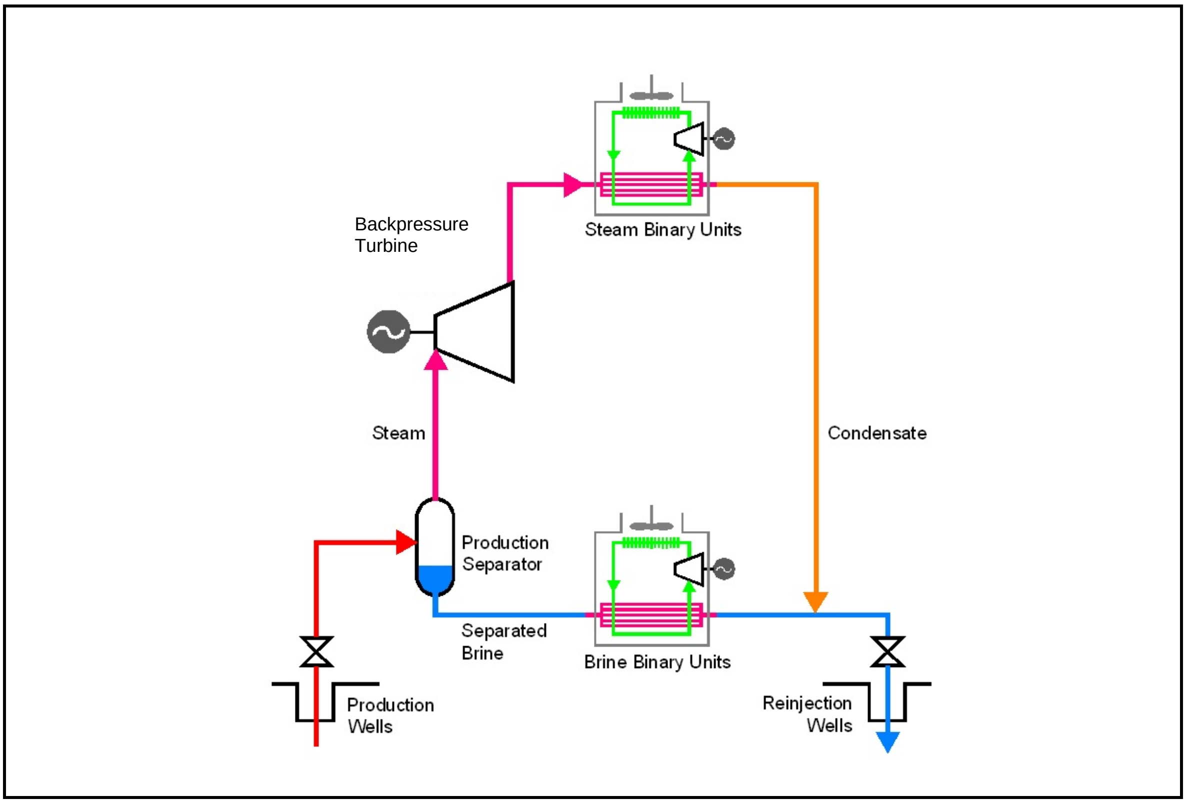
Key points to note are:

(i) Single steam admission pressure to the steam turbine, with steam discharged at low pressure (and temperature) feeding steam ORC units, and high temperature brine-fed ORC units

(ii) Use of preheaters and recuperators to maximise thermal energy recovered

(iii) Use of air cooled condensers, but water cooling could also be applied; the selection of cooling method would be optimised for cost and performance, and

(iv) Multiple ORC units are used (due to maximum unit size of about 10-15 MW).



- **Figure B-5 Geothermal combined cycle unit (hybrid cycle) power plant**