Habanero Geothermal Project Field Development Plan

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DEFINITIONS

Term	Meaning
AFIT	Acoustic Formation Image Tool
ARENA	Australian Renewable Energy Agency
ASX	Australian Securities Exchange
BHA	Bottom Hole Assembly
BOP	Blow Out Preventer
BTC	Buttress Thread Connections
CBIL	Circumferential Borehole Imaging Log
CEFC	Clean Energy Finance Corporation
CRA	Corrosion Resistant Alloy
CT	Coil Tubing
CTU	Coil Tubing Unit
DMITRE	Department of Manufacturing, Innovation, Technology, Resources and Energy
DWOP	Drill Well On Paper
EBITDA	Earnings before Interest, Tax, Depreciation and Amortisation
ECD	Equivalent Circulating Density
EGS	Enhanced Geothermal System
ESD	Emergency Shutdown Valve
FDP	Field Development Plan
GDY	Geodynamics
GEL	Geothermal Exploration Licence (South Australia)
GRE	Graphite Reinforced Epoxy
GRL	Geothermal Retention Licence (South Australia)
GTA	Gas Turbine Alternators
GWP	Global Warming Potential
H01	Habanero 1
H02	Habanero 2
H03	Habanero 3
H04	Habanero 4
HGP	Habanero Geothermal Project
HKO	Hydraulic Kick-Off
HPHT	High Pressure High Temperature
HPP	Habanero Pilot Plant
HPS	Horizontal Pumping System
J01	Jolokia 1
JTD	Jet Turbo Drill
LCM	Lost Circulation Material
LCOE	levelised cost of electricity basis
LWD	Logging While Drilling
MDEA	Methyldiethanolamine
MPD	Managed Pressure Drilling
MRET	Mandatory Renewable Energy Target
MT	Magnetotellurics

Term	Meaning
MWD	Measurement While Drilling
NACE	National Association of Corrosion Engineers
NEM	National Electricity Market
NPV	Net Present Value
O&M	Operations and Maintenance
ORC	Organic Rankine Cycle
P&A	Plug and Abandon
P&T	Pressure and Temperature
PBR	Polished Bore Receptacle
PVT	Pressure, Volume, Temperature
QGECE	Queensland Geothermal Energy Centre of Excellence
RECS	Renewable Energy Certificates
REDP	Renewable Energy Development Program
ROP	Rate of Penetration
SEO	Statement of Environmental Objectives
SPI	Stimulators, Producers, Injectors
STA	Steam Turbine Alternators
TD	Total Depth
TPH	Tonnes Per Hour
TVD	True Vertical Depth
UBD	Under-balance drilling

EXECUTIVE SUMMARY

Geodynamics Limited (GDY) has been exploring enhanced geothermal system resources in the Cooper Basin, near Innamincka, South Australia for the last ~10 years. Enhanced Geothermal Systems or EGS is a type of geothermal development that utilises the heat from hot granite rocks at accessible depths, generally less than 5 km, to generate electricity or produce process heat. This exploration program culminated in October 2013 with the completion of the Habanero Pilot Plant (HPP) project. The HPP project is a demonstration scale 1 MW_e EGS project consisting of two wells, a reservoir enhanced through high pressure stimulation, closed loop circulation for the extraction of EGS heat, and demonstration of electricity generation. It is the first of its kind in Australia and is a globally significant achievement.

In light of the technical success of the HPP project, GDY has investigated the feasibility of a small scale commercial EGS project supplying power/heat to a local consumer in the Cooper Basin, referred to as the Habanero Geothermal Project (HGP). The most suitable customers in the region are gas producers that require significant amounts of power and heat for gas production, processing, and compression. Santos currently has significant existing operations in the region, and new players, such as Chevron and Beach, are planning future production facilities. This document outlines a Field Development Plan (FDP) for the Habanero resource. It discusses at length key learnings acquired by GDY during the exploration of three EGS resources in the Innamincka granites: Habanero, Jolokia, and Savina. It also investigates the commercial viability of a next stage EGS project.

The primary learning of the EGS exploration is that substantial power and/or process heat production is achievable from the Habanero EGS resource.

Evidence strongly indicates that the Habanero reservoir is a single pre-existing fault. Essentially all fluid flow is via this fault with the majority of the granite rock having little or no permeability. To date attempts to create a permeable network of fractures “at will” have been unsuccessful. This finding has resulted in more conservative estimates of the total recoverable energy and the amount of energy that can be produced from one well.

Various models were created and calibrated against HPP data to determine production profiles for a next stage EGS development of the Habanero measured resource. HPP data and a Monte Carlo analysis were used to estimate production and injection flow rates of 25 – 45 kg/s per well, giving most likely estimates of 90 – 120 kg/s for a six well project, and 60 – 80 kg/s for a four well project. In addition, GDY carried out thermodynamic reservoir simulation of the Habanero field with the numerical modelling software AUTOUGH2. The model was used to select the optimum well layout, which was an inverted 4-spot or triangular layout; and to determine temperature drawdown over the 15 year project life, estimated to be ~30°C decline in average bottom hole flowing temperature. In addition, WellCAT casing design software was used to correct the simulated flowing bottom hole temperatures to their equivalent surface production temperatures.

Using this simulation-derived temperature forecast, an assessment of the geothermal resources for three HGP development options has been prepared as detailed in the table below:

Parameter	Units	Value
Area of seismic cloud	km^2	4
Depth range	m	4,000 – 4,500
Thickness	m	500
Volume of granite	km^3	2
Average temperature	°C	243
Cut-off temperature	°C	180
Heat Capacity	$MJ/(m^3.K)$	2.6
Heat in Place	PJ_{th}	330
Recoverable Thermal Energy (2 wells)	PJ_{th}	10
Recoverable Thermal Energy (4 wells)	PJ_{th}	20
Recoverable Thermal Energy (6 wells)	PJ_{th}	30

Drilling deep a high pressure, high temperature (HPHT) EGS well is a significant engineering undertaking. This is especially the case in the Cooper Basin where the extreme process conditions are at the technical limits of conventional drilling technologies. As a result, EGS wells at Habanero are technically challenging and historically have been very high cost. GDY has now drilled six EGS wells in the Cooper Basin and has accumulated a significant body of knowledge in drilling HPHT wells.

During the HPP project, the successful drilling of Habanero 4 demonstrated GDY's ability to drill HPHT wells with high integrity that protects the reservoir from damage. Habanero 4 well design addressed key well integrity issues identified through the failure of Habanero 3. The selected material is resistant to stress corrosion cracking and the use of reverse circulation cementing eliminated the highly caustic environment in the annulus. Intensive modelling of the drilling fluid allowed the main fault to be drilled and completed using weighted, water-based mud without causing significant damage or losses of drilling fluid to the reservoir. Research and development in drilling mud composition also significantly improved drilling performance by preventing temperature-induced breakdowns, increased well bore stability, contributed to increased penetration rates, and reduced downtime. In addition, advancements in bit selection and bottom hole assembly design increased drilling efficiency.

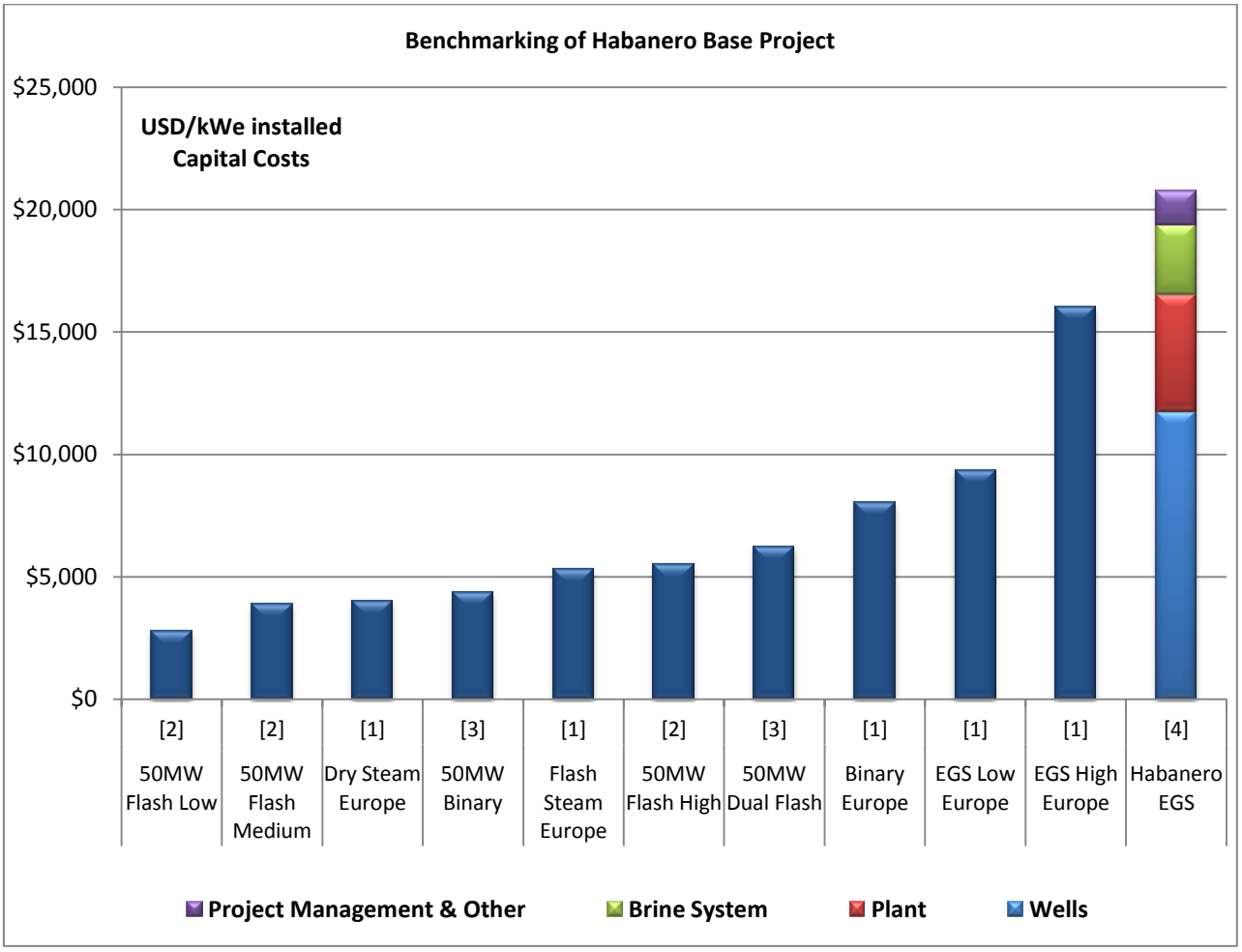
The FDP identifies and discusses drilling methods and well designs that have the potential to maintain high well integrity and protect productivity of the reservoir, while achieving major cost reductions. Key innovations in the well design included reducing the number of casing strings from three to two and reducing hole size through the reservoir from 8.5 inch to 6 inch. Both contribute to reducing rig size and material and time related costs. The completion has been replaced with two fully cemented casing strings that are designed to withstand all foreseeable loads, which reduces complexity, risk and cost. Furthermore, the main fault is to be drilled with a coiled tubing unit and weighted brine rather than conventional drilling rig and drilling fluid; this minimises the risk of damage to the main fault and simplifies operations. These innovations result in a cost reduction from ~$50 million for Habanero 4 to an average per well cost of ~$16.5 million for a five well campaign.

The design, construction and operation of surface equipment at Habanero are also technically challenging and costly due to the extreme process conditions, remote location, and small scale. In addition, the large distance to potential customers and the high availability requirements of a gas production facility can add significant cost to a project.

For the FDP, GDY focussed efforts on capital efficiency. Studies were undertaken to explore the limits of design innovation of power plant cycles, cooling options, brine heat exchangers and piping, and the incorporation of existing equipment. In order to identify the optimum project, GDY

conceptually designed and costed three different sized power projects and one heat project. A six well, nominal 7.5 MW_e project was considered the *'base case'*, and most efforts were concentrated on this option. Alternate development concepts were investigated to a lower level of detail.

One key finding of the FDP was the insight gained into the likely capital costs of a small EGS development at Habanero. The figure below compares the estimated capital cost for the base project, to global geothermal benchmarks from various sources. This graph shows that a Habanero EGS development has a higher specific installed capital cost than other developed geothermal projects. In addition, the figure highlights that while the wells are the dominant contributor to total project capital costs, the brine system also adds significant CAPEX due to the extreme process conditions.



All power projects are considered attractive compared to diesel fired generation, but there is currently no large user of diesel fired generation that could support a 15 year project in the region. Given the high capital costs and resulting high levelised cost of electricity (LCOE), the identified power projects are assessed to be not commercially competitive with gas fired generation, which is estimated to cost ~$80-$120/MWh based on the opportunity cost of gas and including a $40/MWh Renewable Energy Certificate (REC) price.

Although electricity generation is assessed to be expensive relative to available alternatives, direct heat is assessed to be commercially prospective. The direct heat project shows significant potential to be competitive on an unsubsidised basis with gas and to be a commercially viable project. It is estimated to provide heat at \$29 – \$37 /MWh_{th}, or \$8-\$10 /GJ, which is equivalent to a \$6.5-\$8.2 /GJ gas cost with an 80% conversion efficiency

In summary, GDY has made significant progress in the understanding of EGS systems and their potential exploitation. Establishing highly permeable EGS reservoirs is likely to be highly dependent on pre-existing faults. While significant progress has been made and significant improvements are possible, drilling HPHT EGS wells is capital intensive. Although EGS electricity generation in the Cooper Basin is comparatively more expensive than other geothermal developments around the world, an EGS direct heat project has significant potential to be an attractive energy source for future gas producers.

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1. INTRODUCTION

Geodynamics Limited (GDY) is Australia's leading geothermal exploration company, and is a world leading developer of Enhanced Geothermal Systems (EGS). GDY was incorporated as a company in 2000 with the purpose of developing energy from EGS, and was listed on the Australian Securities Exchange (ASX) in September 2002. For most of the last decade, GDY has focused on developing EGS resources in the Cooper Basin, near Innamincka, South Australia.

Enhanced Geothermal Systems or EGS is a type of geothermal energy that utilises the heat from hot granite rocks at accessible depths, generally less than 5 km, to generate electricity or produce process heat. The heat from the granite rocks is extracted by the circulation of water through present fractures or faults, which can be stimulated to enhance productivity by injecting high pressure water to create seismic events. The heated water returns to the surface under pressure, where the heat is converted into electricity via a surface heat exchanger and conventional geothermal power plant technology, or used directly for process heat. EGS has significant advantages over many forms of renewable energy such as the ability to provide base-load electricity (no storage required) with minimal visual and environmental impacts.

GDY holds tenements over ~1,200 km^2 of high heat producing granite rocks, up to 10 km thick, in the Cooper Basin. The resource is collectively known as the Innamincka Granite Resource and includes three explored EGS granite areas: Habanero, Jolokia, and Savina, with measured temperatures of 243°C at 4,200 m (Habanero), and 264°C at 4,600 m (Jolokia). Of these exploration wells the Habanero field is the only areas that to date has been classified as reservoir. The granite resource in the Cooper Basin is one of the best of its kind in the world with estimated temperatures of ~290°C at ~4,900 m. It holds significant potential to produce large scale base load power of >100MW over the long term..

Most recently, GDY successfully demonstrated the technical feasibility of EGS at Habanero with the completion of the Habanero Pilot Plant (HPP) project in October of 2013. The HPP is a demonstration scale 1 MW_e EGS project consisting of two wells, reservoir enhancement through high pressure stimulation, extraction of EGS heat via closed loop circulation, and demonstration of electricity generation. It is the first of its kind in Australia and is a globally significant achievement.

Completion of the HPP project marks the end of a ~10 year field-based research and development program that concluded with proving that electricity can be generated from an EGS resource in Australia. This 10 year program included drilling six deep high pressure high temperature (HPHT) geothermal wells, productivity and injectivity testing of wells, multiple high pressure stimulations to enhance well performance, creation of the world's largest underground EGS heat exchanger, proof of concept through extracting heat via closed loop circulation of fluid through a well doublet, and construction and operation of a 1 MW_e pilot plant.

GDY is currently investigating the feasibility of a commercial scale EGS project at the proven Habanero resource. This document outlines a Field Development Plan (FDP) for the Habanero enhanced geothermal resource situated near the town of Innamincka, in the Cooper Basin, South Australia.

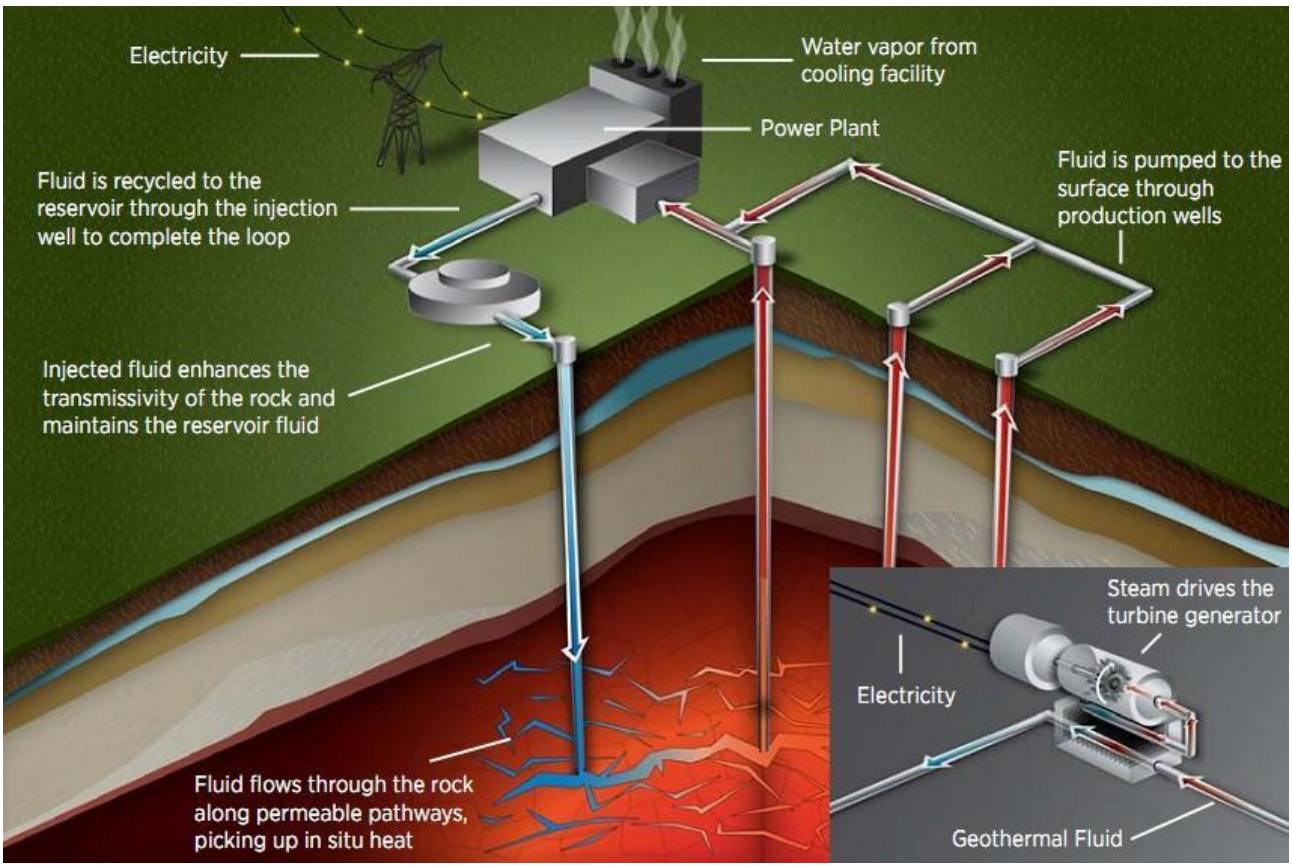


Figure 1-1: EGS Power Generation Concept
(http://alfin2300.blogspot.com.au/2011/02/us-potential-for-geothermal-power-32.html)

1.1 The Project

The Project is referred to as the Habanero Geothermal Project (HGP) and consists of developing the Habanero EGS resource to provide electricity and/or heat to a local consumer in the Cooper Basin.

1.2 The Developer

The FDP has been prepared on the basis that GDY is the sole developer of the project, though joint venture arrangements are being pursued. In May 2014 GDY signed an Exclusivity Agreement with Beach Energy Limited with regards to the Company's geothermal exploration tenements located at Innamincka, South Australia.

Under the terms of the agreement Geodynamics has granted Beach an exclusive right to negotiate a farm-in agreement to the geothermal licences held by Geodynamics for up to an 18 month period.

1.3 Financing and Funding

ARENA Grant funding has been awarded for the development of the Habanero Geothermal Project and further investigations to prove the existence of a second reservoir at Savina.

A variation to the original Grant funding which was received in November 2009 by the Department of Resources Energy and Tourism was approved by ARENA in September 2014. Under the Under the Variation agreed, ARENA will continue to contribute up to $27.15 million of grant funds in support of a revised program of future activities.

1.4 Licence

GDY was granted Geothermal Exploration Licence (GEL) 98, known as the Innamincka block, in October 2001. The neighbouring GEL 97 (Bulyeroo block) to the west was acquired in May 2002. Both exploration licences have since been converted into Geothermal Retention Licences (GRLs) 3 to 12. The combined area of these ten GRLs is 991 km^2.

GEL 211, the Mootanna block, adjoining the southern edge of the Bulyeroo block, was granted to the company in November 2005. A portion of the original licence area was relinquished at renewal in November 2011, leaving the current area of 321 km^2. GDY acquired GEL 268, between the Innamincka block and the SA-QLD border in December 2010. A portion of the original licence area was relinquished at renewal in May 2013, leaving the current area of 313 km^2.

As of 1 July 2013, all these GRL and GEL licences are held 100% by Geodynamics Limited, ACN 095006090. The HGP is planned to be developed within the GRL 3 license area.

The land owner is the South Australian Minister for Environment and Conservation. The Innamincka Pastoral Company has a pastoral lease, and the Yandruwandha/Yawarrawarrka people have native title claim over the site of the proposed activity. Beach Petroleum and Santos have petroleum related licences over GRL 3 and surrounding areas.

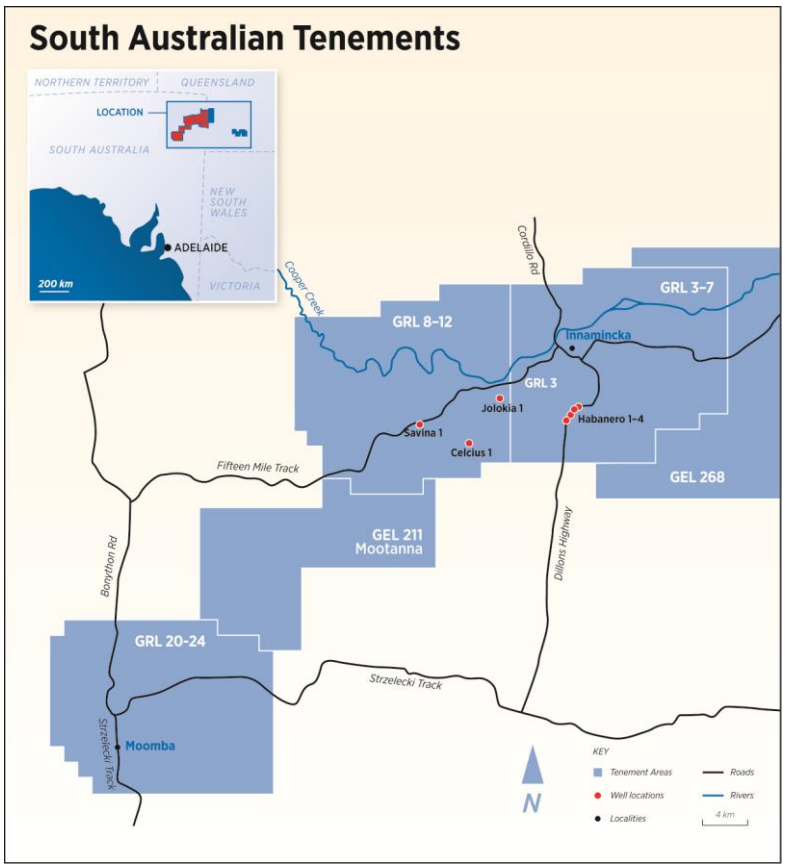


Figure 1-2: Geothermal Tenements

1.5 Community and environment

The Cooper Basin region is a remote location in a desert region situated in the northeast corner of South Australia, approximately 1,000 km northeast of Adelaide and ~1,200 km west of Brisbane. Innamincka, and the Habanero EGS resource, are situated within the Innamincka Regional Reserve which covers an area of ~13,800 square kilometres. The landscape is vast, and the climate is typically dry with little vegetation, except in wet years and times of flood (**Figure 1-3** and **Figure 1-4**).

The Cooper Basin is sparsely populated with little infrastructure built for general inhabitants. Apart from oil and gas exploration, the region is known for its large scale cattle stations, historical significance, and the famous Cooper Creek near where Burke and Wills came to rest. As a result, the area is frequented by tourists, typically during the milder seasons of spring and autumn.

Innamincka is a small town with a population of about 15 residents and consists primarily of a hotel, service station, ranger's quarters, and residential housing. There are some small commercial operators that provide services to the oil and gas industries who are based, or have equipment yards, in Innamincka. Based on the 2006 census, the broader region has an estimated population of 130, with most assumed to be living on the large cattle stations in the area.

The Cooper Basin itself is a sedimentary geological basin that is home to one of the oldest and largest onshore oil and gas fields in Australia. As a result, the basin has significant oil and gas drilling and production activity. The most significant player is Santos, who has operated in the region since 1963. Santos has large scale established production facilities at Moomba (**Figure 1-5**) and Ballera, and a significant number of well fields, gathering facilities, satellite stations, and pipelines. In addition to Santos, numerous other oil and gas players are involved in the region including Origin Energy, Chevron, Beach Petroleum Limited, Drillsearch, Senex Energy, Icon Energy, and Strike Energy.

Most of the significant infrastructure existing in the Cooper Basin has been developed by Santos. It is understood that road maintenance and building is done jointly by Santos and the local shire council. There are jet sized airports located at Moomba (**Figure 1-6**) and Ballera, and reasonably well maintained roads between Moomba and Ballera, via Innamincka, with significant amount of bitumen on the Queensland side. In addition, freight and fuel trucks are frequently travelling to and from the area, making logistics relatively easy for such a remote location. In addition, many service companies are set up in Moomba, and maintenance services and some spares are available.

Figure 1-3: Innamincka township
(http://www.innaminckatp.com.au/)

Figure 1-4: Innamincka in flood
(http://thesentimentalbloke.com/wp-content/uploads/2010/04/Cooper-Creek-Innamincka.jpg)

Figure 1-5: Moomba gas facility
(*http://www.flickriver.com/photos/johnnyd90/tags/moomba/*)

Figure 1-6: Moomba Airport
(*http://www.flickriver.com/photos/johnnyd90/tags/moomba*)

1.6 Project Status

The status of the Habanero Geothermal Project is compared to the main development phases of a typical greenfield geothermal development in **Table 1-1**. This FDP details and analyses existing exploration data from the HPP, presents and recommends geothermal well design and drilling programs, analyses potential development scenarios, presents financial modelling for potential development options, highlights critical uncertainties, and recommends items for further work.

Table 1-1: Comparison of HGP status to a typical greenfield geothermal development

Exploration Phase	Typical geothermal project	Habanero Geothermal Project
Pre Feasibility	• Geology, structure and alteration mapping • Geochemistry sampling of key geothermal manifestations • Geophysical surveys (Magnetotelluric - Time Domain Electromagnetic) and interpretation • Shallow well drilling and data logging • Thermal gradient and soils permeability assessments • Data integration and definition of exploration strategy and drilling targets for the development phase • Pre-feasibility (conceptual) studies for the steam field, power plant and transmission. Comparison of various conversion technologies • Evaluation of legal and environmental issues related to geothermal development	• Completed • Not relevant • Not relevant • Completed • Completed • Completed • Completed • Completed with HPP
Development Phase	**Typical geothermal project**	**Habanero Geothermal Project**
Feasibility	• Drilling of first full size discovery well(s) • Confirmation of the resource characteristics, size, boundaries • Well tests and reserve estimates. Determine mass flow, steam flow and enthalpy of the resource. Define project design parameters. • Preliminary design of the plant, including size, location of wells, separators, power station and energy transmission (own use or export or both), economic appraisal and identification of possible suppliers and their timelines • Financial modelling of various development alternatives and decision to proceed in detailed design and construction phase of 1 alternative • Solve legal, environmental and financing issues to clear way for construction phase.	• Completed • Completed • Completed • Completed • Purpose of FDP, decision to proceed to be based on FDP • Not yet Completed
Execution	**Typical geothermal project**	**Habanero Geothermal Project**
Project Implementation	• Execution of production drillings and re-injection drillings for the specified development. • Detailed design of civil works as well as steam field, power plant and transmission equipment. Prepare specifications. Outsource plant equipment, control manufacturing, transport erection and commissioning.	• Not yet Completed
Operation and Maintenance	**Typical geothermal project**	**Habanero Geothermal Project**
Wells, Steam field and Power Plant Operation and maintenance	• Make-up wells, wells work-over and acidizing • Routine and planned maintenance of all equipment • Monitoring and adjustment of resource and power station operating parameters • Optimisation of resources and operations and maintenance costs	• Not yet Completed

2. THE MARKET

The HGP is a small scale EGS project that intends to deliver electricity and/or heat to a local consumer in the Cooper Basin. This section discusses potential loads and customers.

2.1 Santos' Moomba and Satellites Electrical Loads

Through review of publically available information, a picture of the existing loads and energy consumption trends of Santos' Cooper Basin operations has been formed to identify potential applications for EGS in the short term.

The electrical load at Moomba is ~8 MW_e. There is reportedly ~20 MW_e of plant capacity installed at the site, in various stages of hot and cold stand-by.

In addition, Santos operates numerous satellite compressor stations scattered throughout the region (**Figure 2-1**). Reportedly each satellite station has a load of 1-2 MW_e, and understood to be driven by gas reciprocating engine driven compressors. Two of these stations, Della and Dullingari are located closer to Habanero than Moomba (**Figure 2-2**). By electrifying the drives of these compressors, there is an opportunity to save fuel gas, and reduce the associated OPEX cost and effort.

It is understood that diesel generation is only used in remote well locations and for camps at some satellite stations such as Dullingari. Camp loads are typically small, ~100 kW_e, and will likely not justify transmission costs in their own right. The diesel loads on remote wells are often in situ for only short periods of time, less than three years, which suggests that they may not be suitable for displacement by an EGS project with a project life of ~15 years.

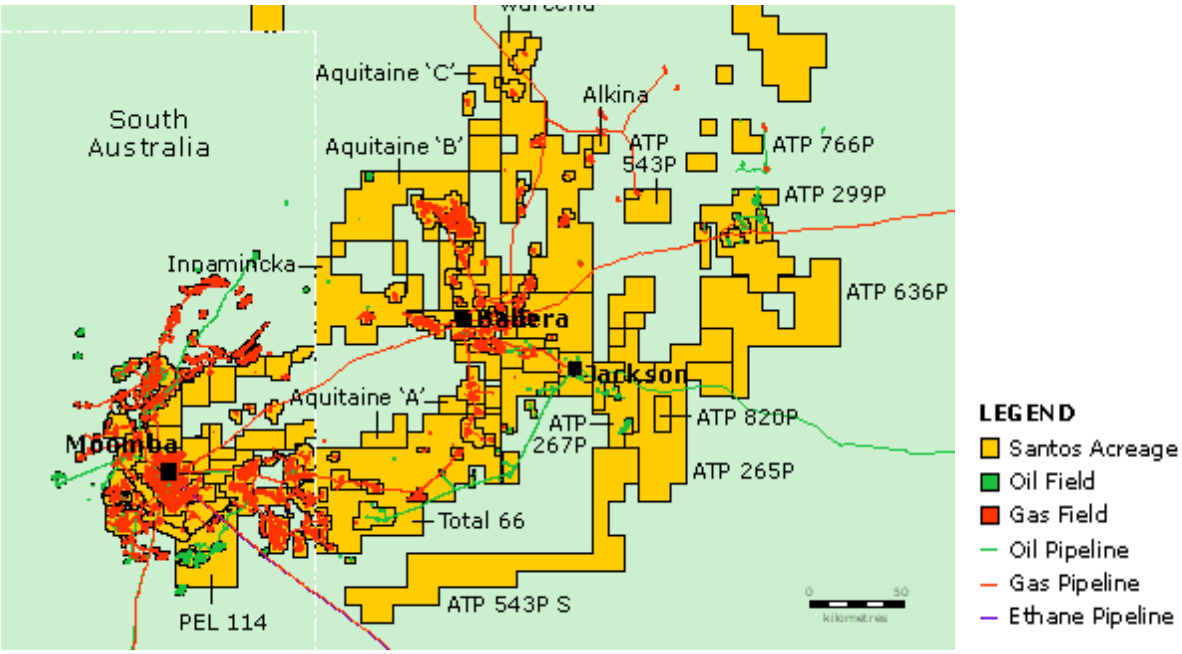


Figure 2-1: Santos' footprint in the Cooper Basin (Santos Limited)

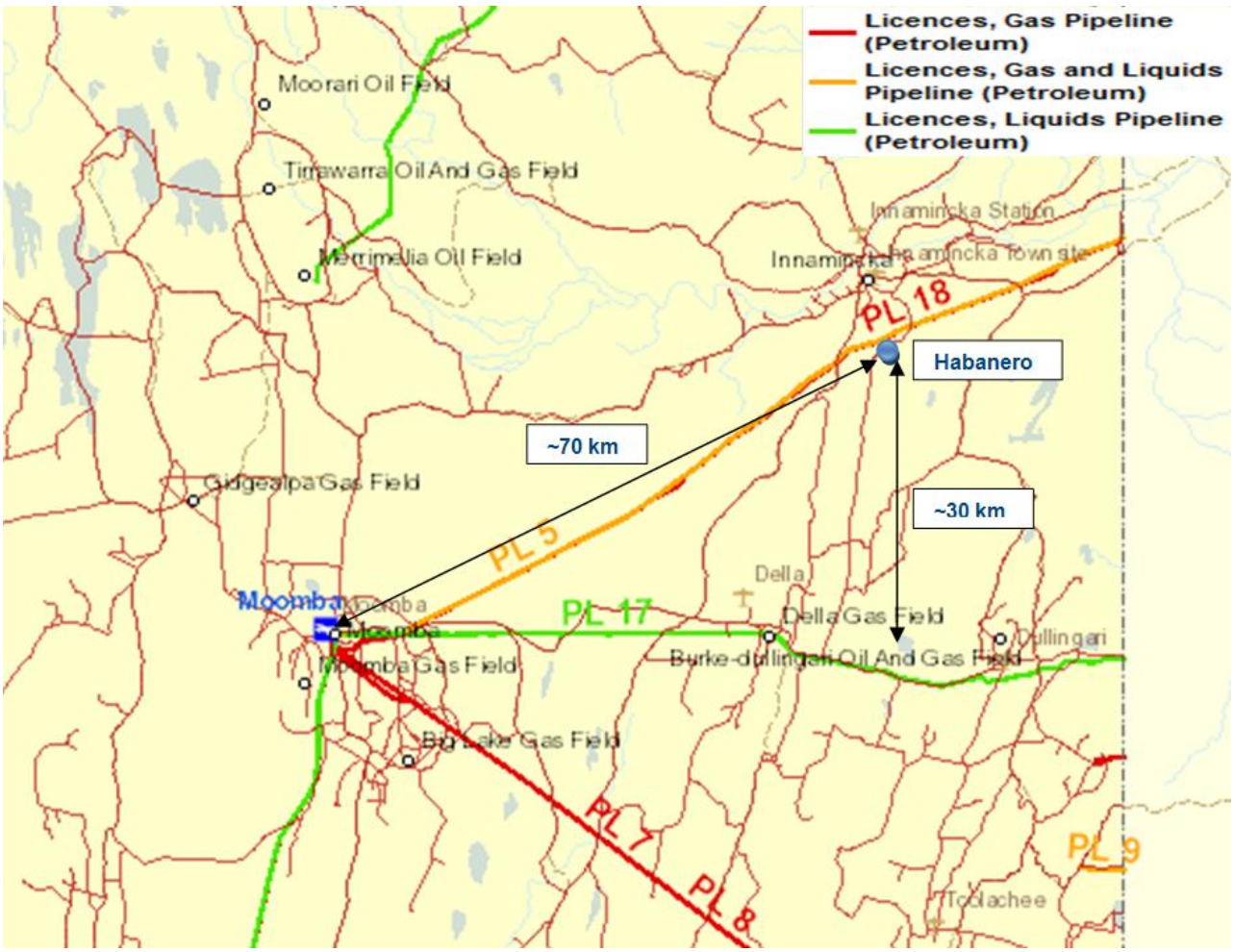


Figure 2-2: Location of Habanero relative to Moomba and Satellite stations (SARIG, PIRSA)

2.2 Other Cooper Basin Oil and Gas Producers Electrical Loads

As mentioned, there are numerous other oil and gas players active in the region, but there are no known existing facilities of a size sufficient for a multi well EGS project. Many of these relatively new players are thought to be currently producing direct from the well to truck or via commercial arrangements with Santos (**Figure 2-3**, **Figure 2-4**).

However, given the significant increase of exploration activity by parties other than Santos, and discussions with some producers regarding development aspirations, it is apparent that new loads may present themselves in medium term. Potential future customers include Chevron, Beach, and Senex, with drilling being undertaken in the immediate area surrounding Habanero (**Figure 2-5**). The timing, size, and location of gas plants or compressor stations are uncertain at present; however, GDY is actively engaged in dialogue and will remain informed about future plans.

While little detail is known about future development plans for these producers, Moomba and Santos' broader operation give an indication of the type and size of potential loads. It can reasonably estimated that satellites stations with loads of 1-2 MW_e, and a production facility with a loads of 4-8 MW_e will be part of a future major gas production development.

These potential new projects give rise to the possibility of a co-located production facility and EGS plant at the Habanero site, which could realise synergies of shared infrastructure and take advantage of the elevated and logistically superior location. Importantly, this would enable the most efficient, reliable, and cost effective integration of EGS into such a facility as it could be designed in from the start. Furthermore, it would significantly increase the attractiveness of geothermal energy being supplied as direct heat.

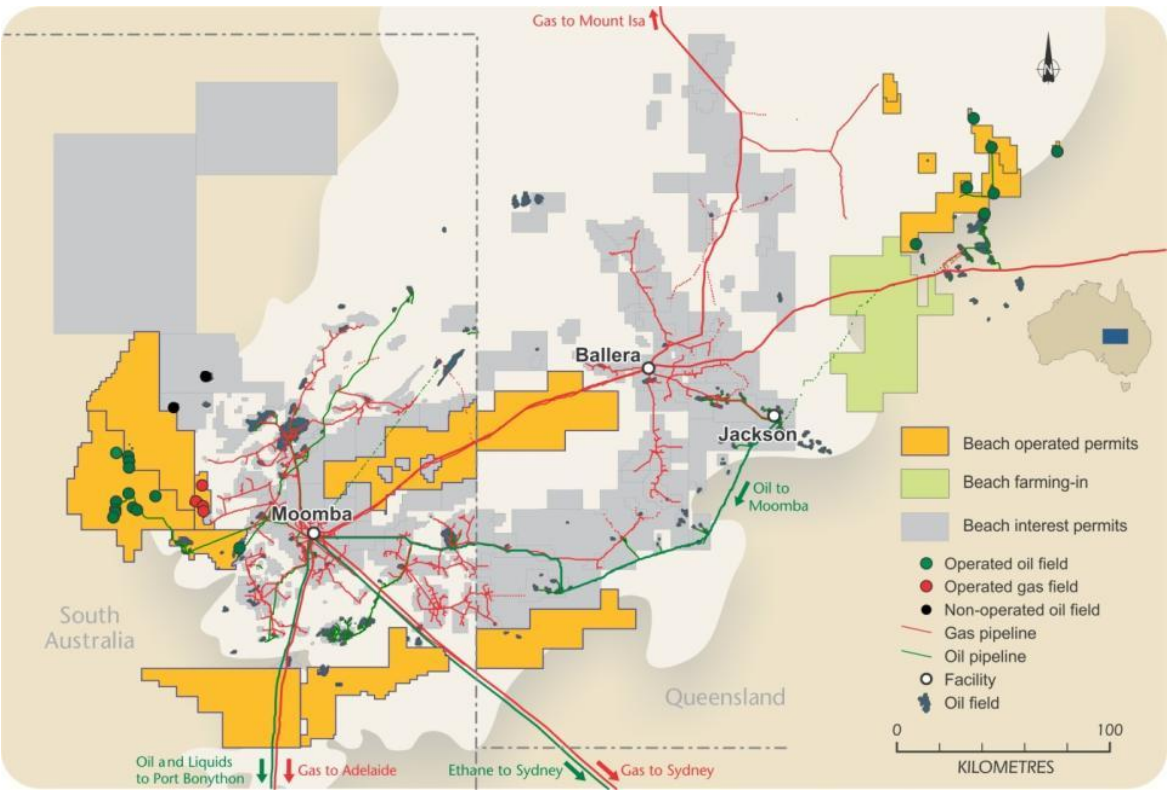


Figure 2-3: Beach Energy presence in the Cooper Basin (Beach Petroleum)

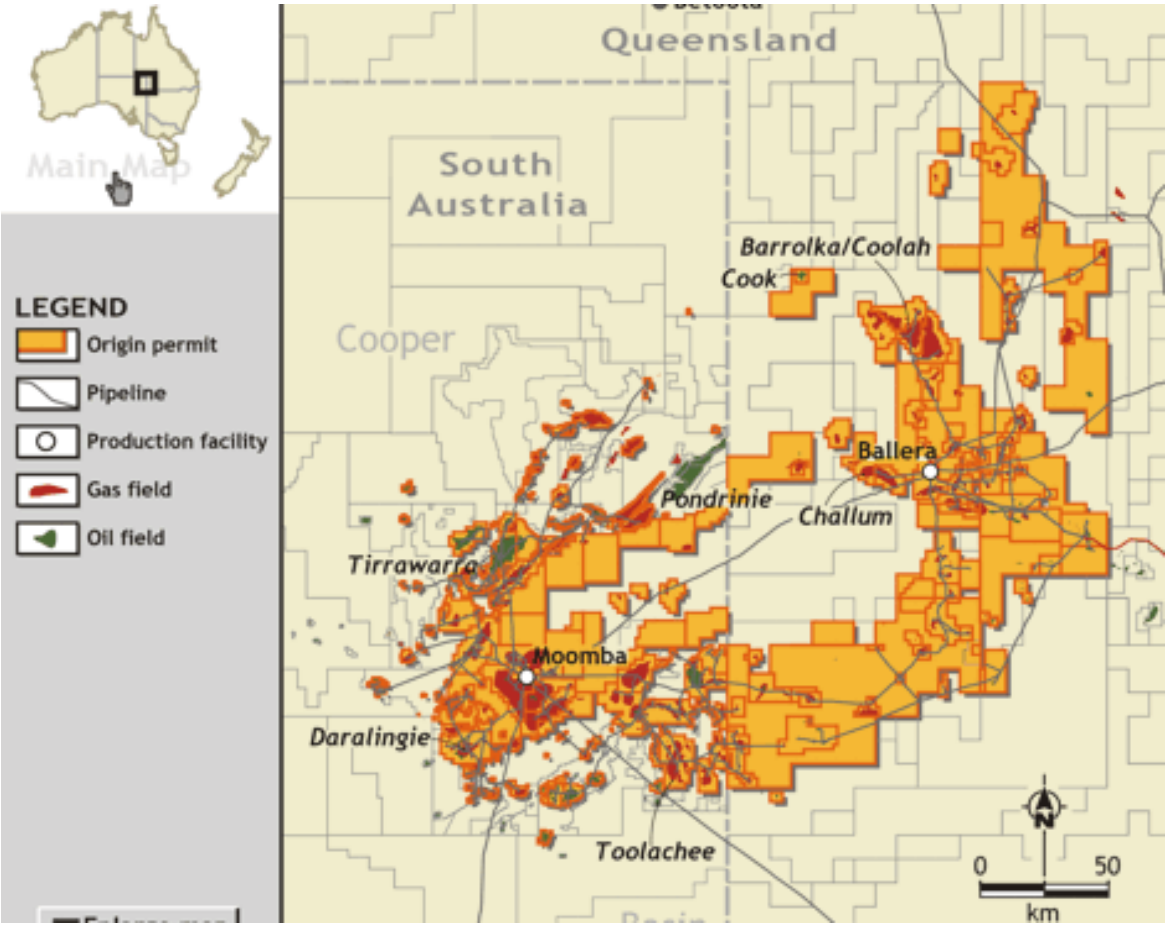


Figure 2-4: Origin Energy presence in the Cooper Basin (Origin Energy)

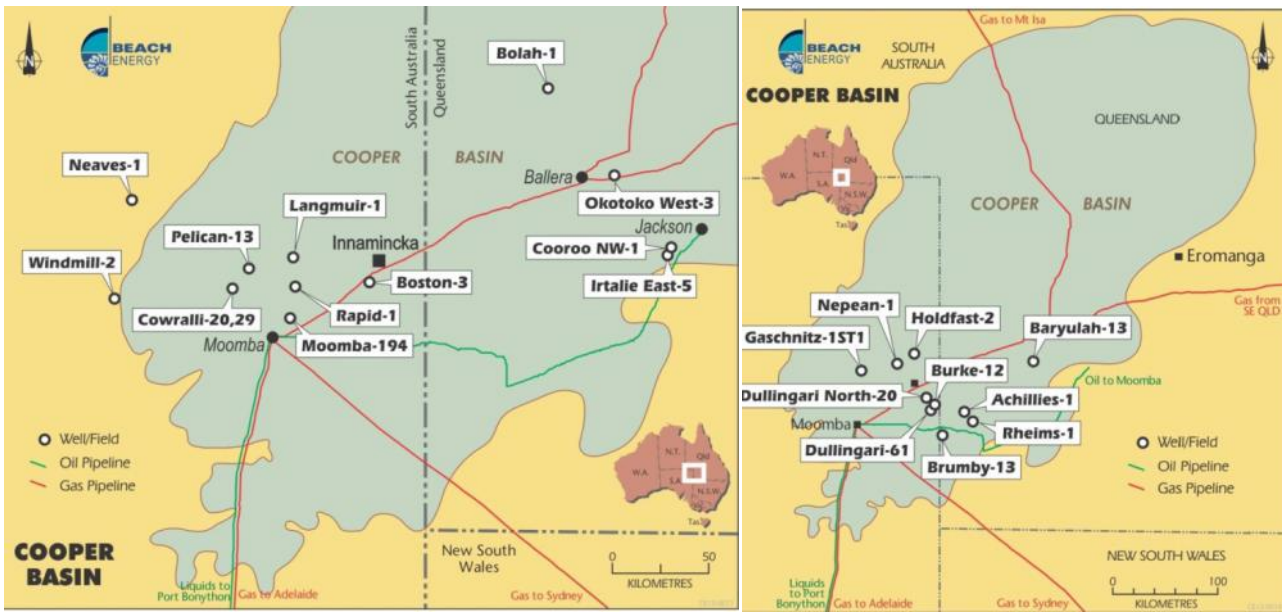


Figure 2-5: Recent exploration wells drilled involving Beach Energy near Innamincka (presented by Beach Energy on different maps)

Figure 2-6: Beach Energy's Christies Facility Cooper Basin (Beach Energy)

2.3 KJM, Innamincka and Other Commercial Electrical Loads

In addition to the gas producers, there are a number of other smaller existing or potential loads in the region such as the Innamincka township, Innamincka station, and commercial operators providing services to the oil and gas industry.

KJM are planning to develop a common infrastructure camp in the Cooper Basin at the location (see **Figure 2-6**), and have approached GDY with interest in EGS supplied power. This camp would otherwise generate power using KJM's fleet of diesel generators. The camp power demand is expected to build gradually and may approach 1MW. An average value of 500 kW_e may be assumed for a life of eight years.

Studies have been previously carried out on the Innamincka and immediately surrounding loads when GDY was considering supplying these loads from the 1 MW_e demonstration plant (**Figure**

2-7). ETSA (2008) reported Innamincka to have an estimated load of 295 kW_e, and Innamincka station to have a load of ~50 kW, with an estimated load factor of 0.4 to 0.5. Assuming 5%pa load growth, the current load might be ~440 kW_e, which at a load factor of 0.5 would give an average load of ~220 kW_e, and annual consumption of ~2,000 MWh.

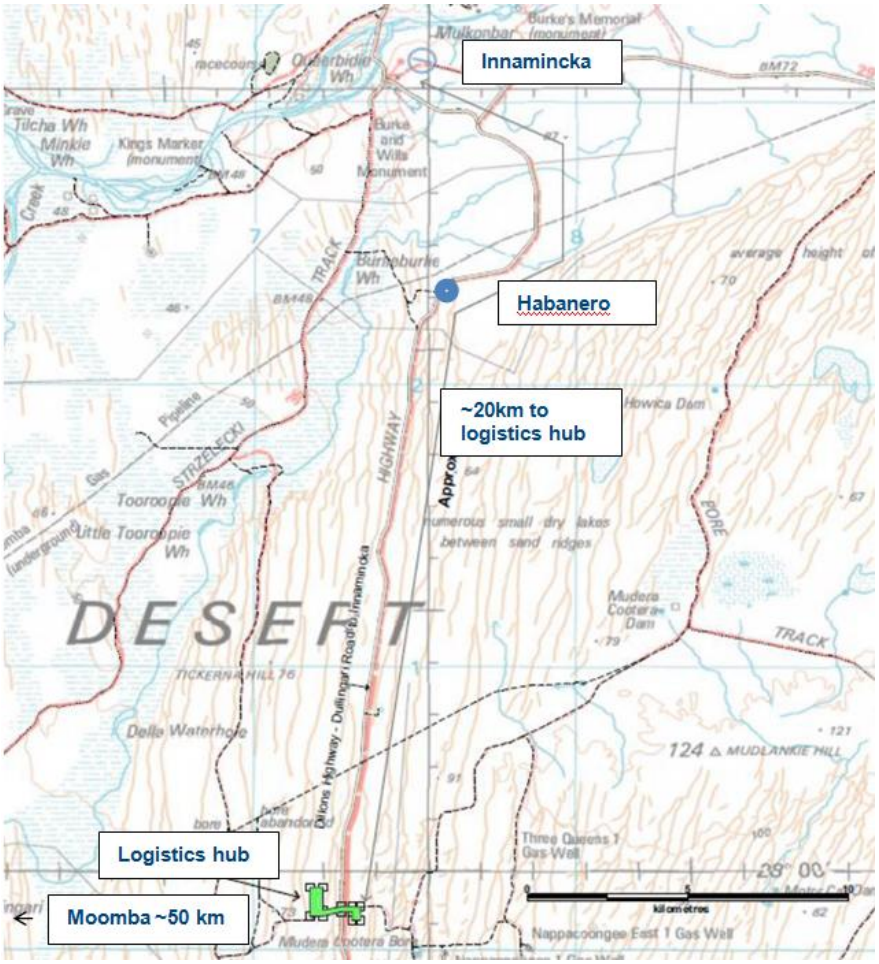


Figure 2-7: Location of planned logistics hub relative to Habanero

Site	Estimated current load
Innamincka Hotel	170kW
Trading Post	55kW
NPWS Service Centre	10kW
Innamincka Homestay	15kW
Earthmovers/Laundrette	35kW
Osborne Residence	10kW
NPWS Residences & Workshops	10kW
Telstra Communications facility	5kW
OACDT Ablutions facility	6kW
Innamincka Station	50kW
Aboriginal Interpretive Centre	-
Bulk Fuel Depot	-
TOTAL	**345kW**

Figure 2-8: Estimated Innamincka Loads in 2008 (ESTA 2008)

2.4 Direct Heat

Geothermal energy can also be sold as direct heat to local gas producers for use as process heat or for preheating feedwater for steam generation cycles. Geothermal energy is particularly well suited to direct heat applications because there is no significant conversion efficiency loss as there is when converting geothermal energy into electricity. As such, geothermal energy is much more competitive with conventional technologies on a direct heat basis.

A significant use of heat in gas processing plants is the removal of CO_2 from produced gas. It has been reported that some unconventional gas wells coming online in the Cooper Basin have CO_2 contents as high as 30%. As such, there may be significant potential for geothermal heat to be used in this application.

The Benfield process is used at Moomba for the removal of CO_2 from produced gas, which is based on hot potassium carbonate. The Benfield process was found to use heat at temperatures between 50°C and 116°C (see **Figure 2-9**). Reportedly, the Amine MDEA (Methyldiethanolamine) based process has significant commercial advantages over the Benfield process and may be the process employed at a new production facility (Oil & Gas Journal 2012, www.ogj.com). In this process the absorber operates at 30°C to 50°C, and the regenerator at 115°C to 126°C (see **Figure 2-10)**.

Geothermal could also be used for feedwater heating (**Figure 2-11**) in a combined cycle or gas boiler based processing plant. Feedwater heating is typically done by extracting steam from the steam turbine; this reduces steam flow through the turbine, but increases overall cycle efficiency. Geothermal heat could be used for heating the feedwater before it enters the heat recovery steam generator of a combined cycle plant, or the boiler of a steam based plant, which would offset the consumption of gas significantly. The integration of geothermal heat might be most simplistically achieved by this method, given that gas processing plants are typically complex arrangement of heat use and heat recovery. It is also likely to result in maximising the use of geothermal heat as normal maximum temperatures are ~500°C and minimum temperatures are around 40°C-50°C.

It is estimated that the Moomba plant consumes approximately 200 tonnes per hour (TPH) of steam with 50 TPH available as hot reserve. Steam conditions for the corresponding input energy have been assumed to result in an estimate of 100 MW_{th} which is broadly compatible with the estimated steam production.

More information would be required as to the proportions of high and low pressure steam in the plant, and uses of steam, to determine the exact load available for low grade geothermal heat; however, at this stage of the project an assumed heat load of 30-60 MW_{th} seems reasonable. With regard to Moomba, there are two important unknowns: what is the temperature that the Moomba plant could draw the heat transfer medium (water) down to, and what extent of re-engineering would be required in the plant in order to receive and distribute the heat.

A new gas plant constructed by another gas proponent in a location close to Habanero may be more attractive in that heat distribution can be designed into the plant from its inception, and expensive long pipelines are not required. A co-located plant is likely to maximise the benefits of using geothermal as a direct heat source by minimising capital costs and temperature losses. It is assumed that such a plant would have similar loads to that of Moomba.

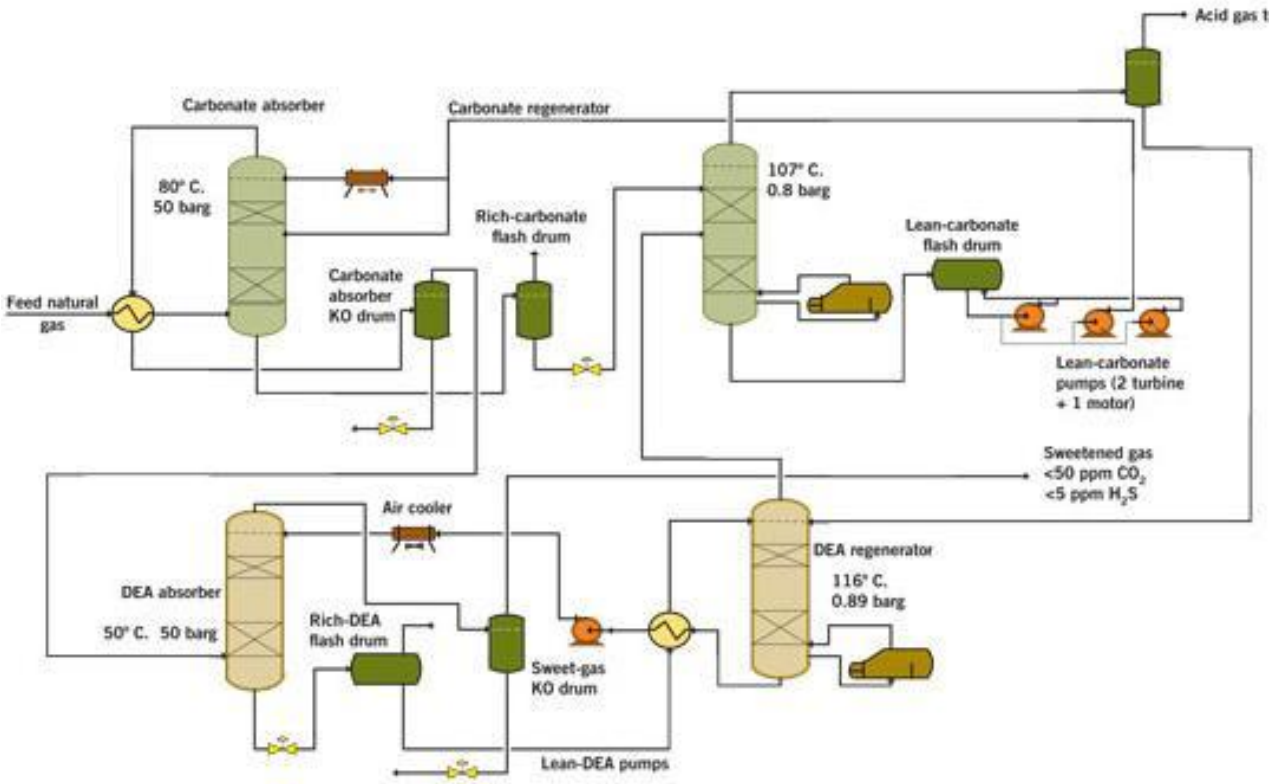


Figure 2-9: Benfield HIPURE process
(*http://www.ogj.com*)

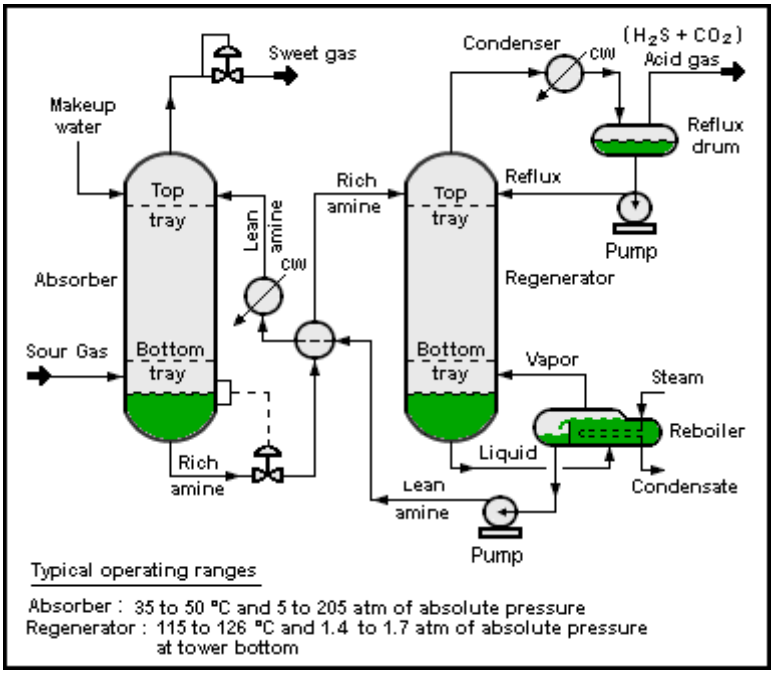


Figure 2-10: Typical amine gas treating process
(*http://en.wikipedia.org/wiki/Amine_gas_treating*)

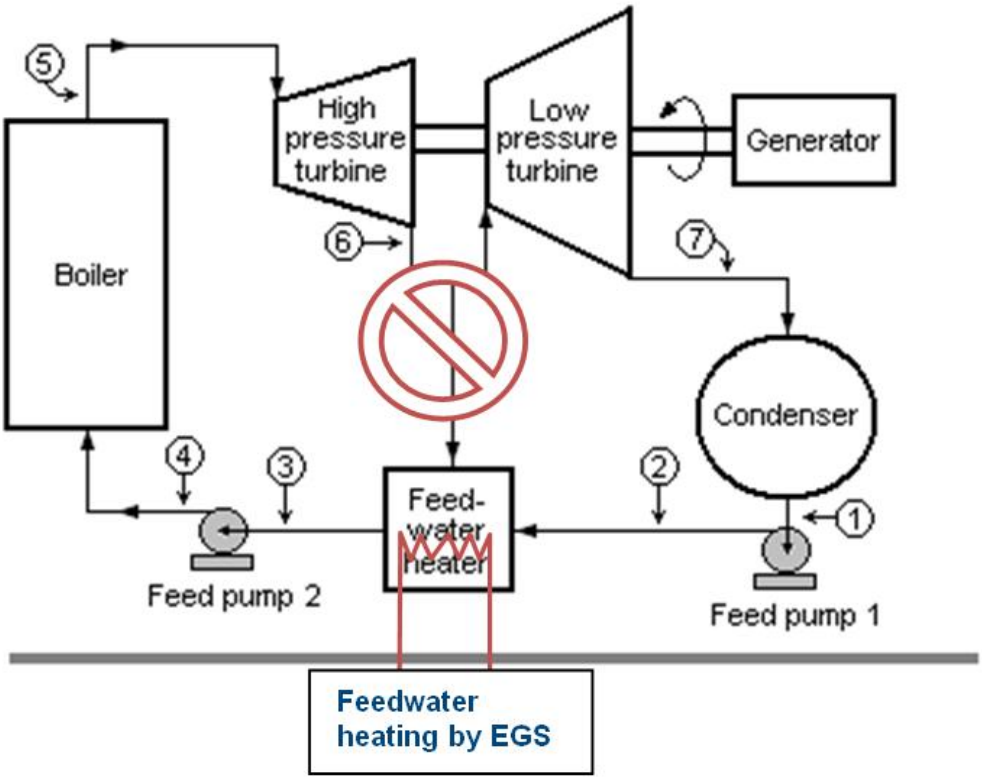


Figure 2-11: Feedwater heating concept using EGS
(*http://en.wikipedia.org/wiki/Steam-electric_power_station*)

2.5 Competing fuel costs

2.5.1 Gas

For the supply to gas producers, the FDP is based on the assumption that EGS is competing with the opportunity cost of gas. That is the price that gas producers are foregoing when they consume gas for production loads rather than sell it.

The following assumptions are used to estimate what the opportunity cost of gas might be:

- Price of LNG unloaded at point of delivery A$14 /GJ
- Shipping and processing cost A$1 /GJ
- Liquefaction cost A$4 /GJ
- Pipeline transmission costs A$0.70 /GJ

These assumptions suggest an opportunity cost of gas at Moomba (or equivalent plant) to be $7-9/GJ. As producers would typically convert gas to electricity using steam turbine alternators (STAs) or Gas Turbine Alternators (GTA), an equivalent cost of electricity generation is estimated to be between $70 and $90 /MWh$_e$. It should be noted that this is a rough approximation, and the real opportunity cost of gas to a specific producer will be dependent on their costs of delivery and supply contracts. In addition, this cost does not include other costs of competing generation technologies such as capital, and operating and maintenance costs. However, these will vary considerably depending on the operating philosophy and operating age of the load. For the purposes of the FDP, the competing cost of gas generation is assumed to be ~$80 /MWh$_e$.

When considering direct heat use rather than electricity generation, using the previous assumptions on the gas cost of electricity generation, the gas cost of heat generation in the form of

hot water equates to between $30 and $40 /$MWh_{th}$. This is equivalent to a gas price of $7-9 /GJ plus conversion efficiency losses of ~20% (i.e. $7 /GJ x 3.6 GJ/MWh ÷ 80% = ~$30 /MWh).

Direct heat has the potential to be a better application of geothermal energy due mainly to the elimination of the large conversion efficiency losses associated with converting low grade heat into electricity. To give an example of the advantage of using geothermal energy as direct heat, if 60 MW_{th} of geothermal heat could be sold at $30 /$MWh_{th}$, the revenue would be approximately $1,800 /hr. Alternatively, converting this heat into electricity would only realise ~$600 /hr of revenue ($80 /MWh_e x 7.5 MW_e x 1hr = $600 /hr).

2.5.2 Diesel

GDY's experience with camp operations in the Cooper Basin has been that diesel fuel costs approximately $2 /litre delivered. Based on the efficiency of generators in the 500 kW_e size bracket, the fuel cost for KJM (and similar enterprises) would be approximately $480 /MWh (excluding other operating costs). Even allowing for the diesel fuel rebate and the discounted fuel costs that KJM may be able to negotiate, this indicates a premium customer with a very different cost of generation to the Santos gas plant.

A project to supply Santos or another gas producer, which routes its power line via the KJM camp, could expect to sell this portion of its power for perhaps $350 /MWh in order to adequately undercut the diesel alternative and secure an agreement.

2.6 Carbon prices

Geothermal energy is virtually emissions free and has a significant lower environmental footprint than the consumption of gas or diesel for energy generation. If gas producers were financially liable for their carbon emissions, then geothermal energy could offset this liability by reducing carbon emissions and provide additional value. Effectively this would translate into higher competing gas and diesel costs.

However, given the significant uncertainty of carbon pricing in Australia at present, it is very difficult to justify the inclusion of carbon pricing in the assessment of projects that may depend on it for viability. As such, carbon pricing has not been included in the study.

3. GEOTHERMAL RESOURCE

3.1 Wells and Geophysics

3.1.1 Early Petroleum Drilling

The deep geothermal exploration wells drilled by GDY are all located close to early petroleum wells. Habanero is close to McLeod, Jolokia is close to Burley and Savina is close to Bulyeroo. The primary targets of each of these petroleum wells were the Permian Toolachee, Patchawarra, Epsilon and Tirrawarra Formations located on apparent seismic highs within the Nappamerri Trough. All three petroleum wells encountered gas-saturated but tight reservoirs. In all three petroleum wells, basement was reached before TD and found to be granite. Five metres of granite core was recovered from McLeod (**Section 3.2.1**).

3.1.2 Gravity Data

The extent of the Innamincka Granite is interpreted from regional gravity data acquired over several gravity surveys. The granite shows up as a distinct gravity low (**Figure 3-1**) which extends beyond the outline of the original GELs 97 and 98.

In August 2002, CSIRO produced a report on magnetic and gravity models for GEL 97 and 98. They used all publicly available datasets at the time, including gravity, magnetic, seismic and well data. To quote their conclusions, “Computer modelling of the gravity has assisted in identifying the depth and boundaries of the large batholitic complex that underlies GEL 97 and GEL 98.” In August 2003 and April 2011, additional gravity data was acquired over the Innamincka Granite area to help define the edge of the granite. This new data significantly improved the reliability of the gravity interpretation but did not change the overall picture.

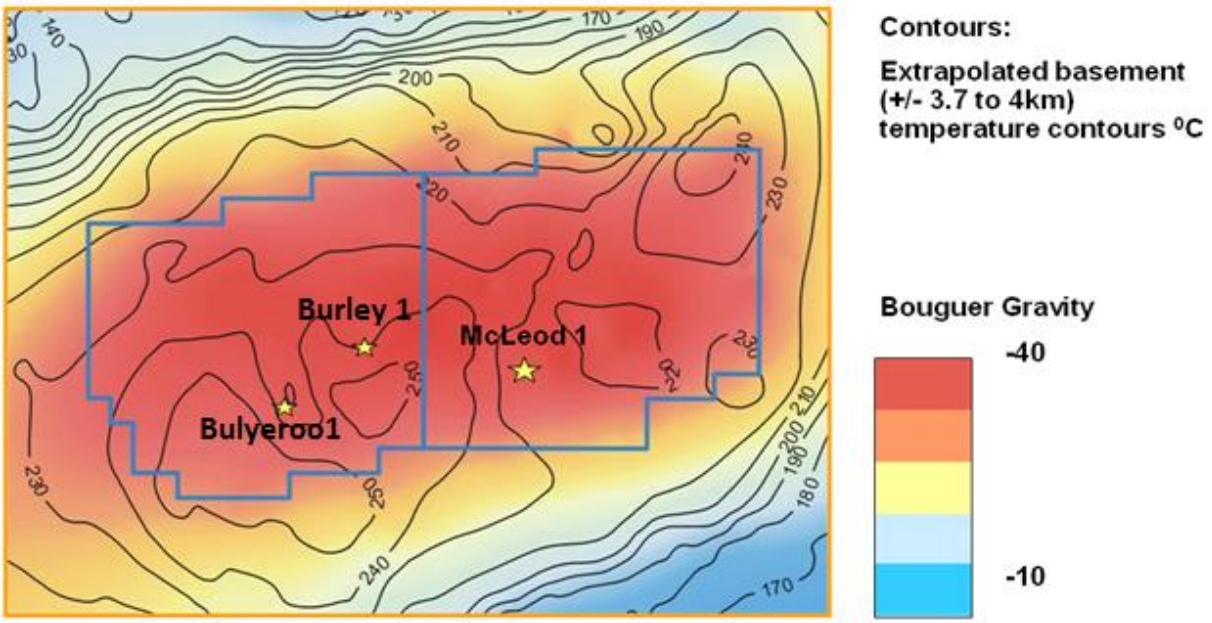


Figure 3-1: Bouger Gravity anomaly over the Innamincka Granite overlaid with extrapolated temperatures at top granite (basement) and the outline of the two original geothermal exploration licences, GEL 97 (Bulyeroo) to the west and GEL 98 (Innamincka) to the east.

Geoscience Australia has been continuing with a project to help delineate the 3D geometries of the known high-heat producing granites through the inversion of gravity data within the Cooper Basin. From this work, the granite under the Habanero area appears to have a thickness of over 10 km.

3.1.3 Magnetic Data

Magnetic data for the region is available, but is of little use for EGS exploration. As part of the CSIRO report produced in 2002, they reported that “the granodiorite is essentially non-magnetic and modelling of the moderate amplitude, broad, magnetic anomalies does not require any sources to a depth of 10 km. The low amplitude, high frequency anomalies mapped in the area arise from shallow sources.” They go on to report that “There is no evidence in either the magnetic or the gravity for lineaments and faults in the GEL tenements”.

Further independent studies concluded that there was a clear consensus between various investigators that there was little possibility of recovering anything of interest with respect to basement depth from the magnetic data. Equally, the possibility of extracting any lineament information relative to the basement is unlikely due to the interference from magnetic units in the sedimentary section.

3.1.4 2D Seismic Data

Seismic data has been acquired over the area by Santos over the period 1972 to 1994. An example of the seismic data over the old GEL 97 and GEL 98 licences can be seen in **Figure 3-2**.

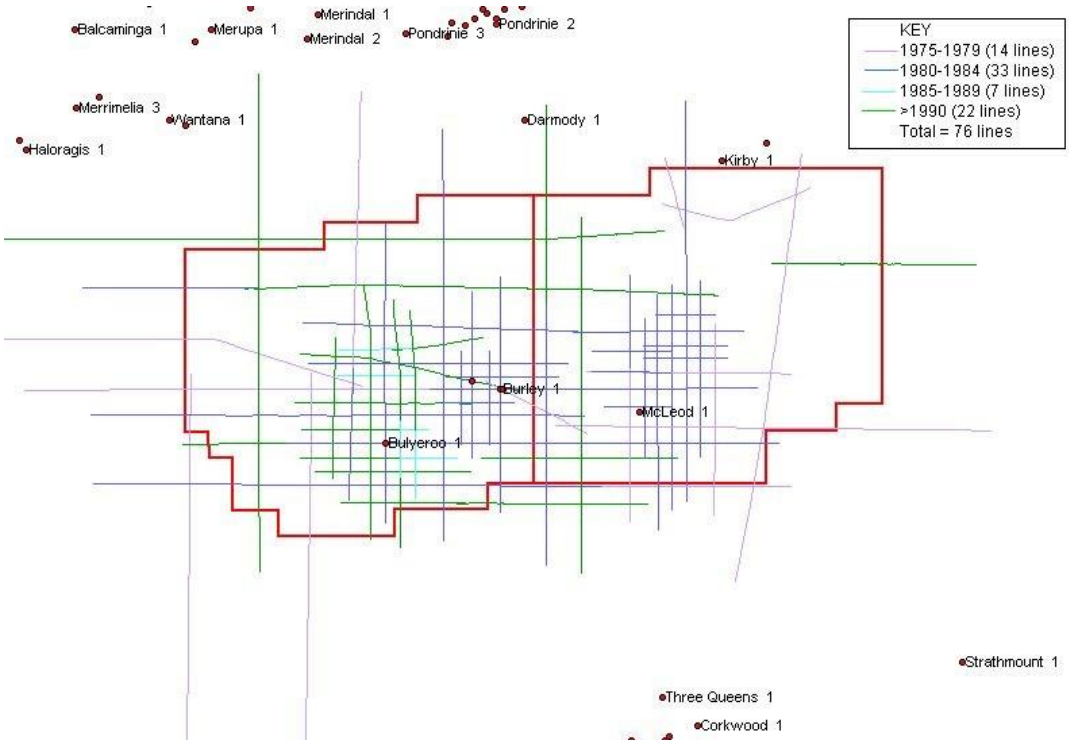


Figure 3-2: Seismic lines over Innamincka granite area

The seismic data is multi-fold and was acquired with short offsets designed to enhance the interpretation of the basin sediments above the granite. Past interpretations have focused on the structuring in the sediments together with attempts to map basement. There was no specific processing to define basement with interpretation primarily driven by well intersections.

In 2002, CSIRO completed a project to reprocess and analyse seismic lines 92-DRP-1, -2 and 83-NCA which ran through Bulyeroo 1. The aim of this process was to distinguish fractures within the granite batholith. Reprocessing of the existing data resulted in an improved overall quality of the final stacks which improved the confidence in the interpretation of the sediment-granite contact. However, the report concluded that the acquisition geometry used was not appropriate for in-depth

analysis of granite bodies, considering target depth of around 3.5-4.0 km but the maximum offset of only 2,000 m in existing seismic surveys. Detailed analysis of granite properties would require new, dedicated acquisition and that only limited analysis is possible with current data sets.

3.1.5 Magnetotelluric Data

Magnetotellurics (MT) is an electomagnetic geophysical method of imaging the Earth's subsurface by measuring natural variations of electrical and magnetic fields at the Earth's surface. This exploration method is commonly used in mineral, geothermal and petroleum exploration. Typical examples of MT in exploration include the identification of highly conductive clay cap regions commonly associated with conventional geothermal areas or detecting resistivity variations in subsurface structures which can differentiate between structures bearing hydrocarbons and those that do not.

Two electromagnetic surveys have been undertaken by researchers from Japan but neither survey was able to provide additional information about the Habanero reservoir.

An additional MT technique is currently being tested in the Habanero area through a research project by the University of Adelaide. This is a three year project with one aim to try to image the stimulated fracture within the granite by comparing MT data pre- and post- stimulation. This method has had positive results in other EGS projects, including Paralana, South Australia. Results from this study will not be known for some time and are unlikely to have an influence on the current development of the Habanero resource.

3.1.6 Top Granite Structure at Habanero

In 2003, Brent Geophysical Consulting was consulted to identify, using seismic interpretation, the presence and orientation of faulting within the Big Lake Suite Granites and to seismically map the top of this horizon. They concluded that it is effectively impossible to image faulting below the top of basement on the current data available. The top granite interpretation by Brent Geophysical Consulting is shown in **Figure 3-3**.

Further interpretation of all seismic was also carried out by consultants MBA Petroleum in 2010. This work resulted in the mapping of four key horizons over the Habanero area in depth. These horizons were the tops of the Mackunda, Cadna Owie, Toolachee Formations and Granite. This interpretation is very similar to that shown in **Figure 3-3** and has been one of the primary inputs into the production of a 3D structural static model for Habanero.

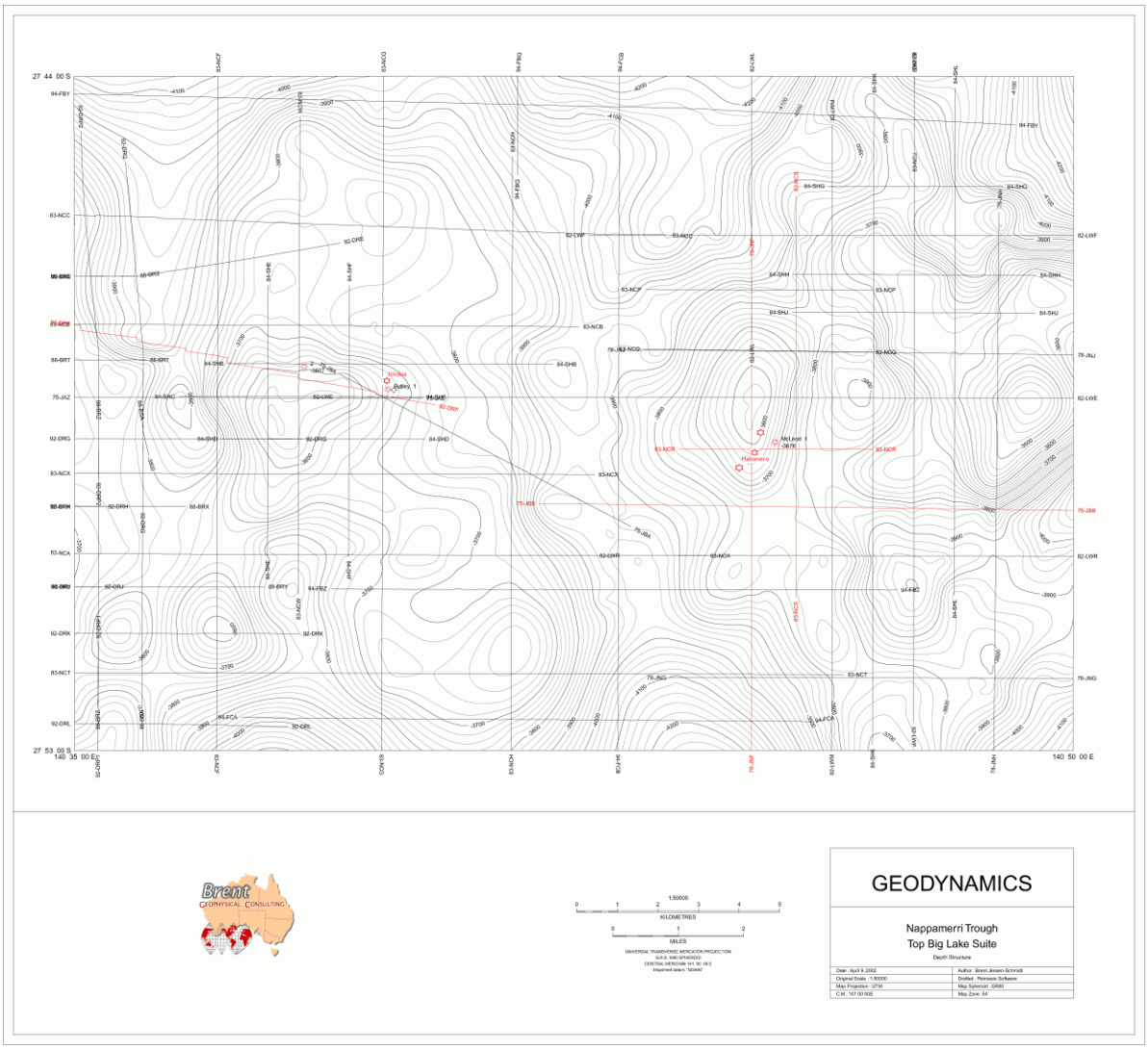


Figure 3-3: Seismic contour map of the top the Big Lake Suite in depth.

3.2 Geology

3.2.1 Petrology

All Habanero wells intersected broadly similar igneous rock types and hydrothermal alteration assemblages. The Innamincka Granite is coarse-grained, white, felsic syenogranite containing quartz, perthitic microcline with subordinate plagioclase, and former biotite which has mostly been altered to chlorite. Lesser mineral phases are muscovite, carbonate and tourmaline. Narrow aplitic dykes are also present. The Habanero aplites are fine grained rocks consisting of abundant quartz, albite and perthitic alkali feldspar.

Figure 3-4 shows part of the core cut in granite at McLeod 1 and **Figure 3-5** shows granite cavings recovered from Habanero 4.

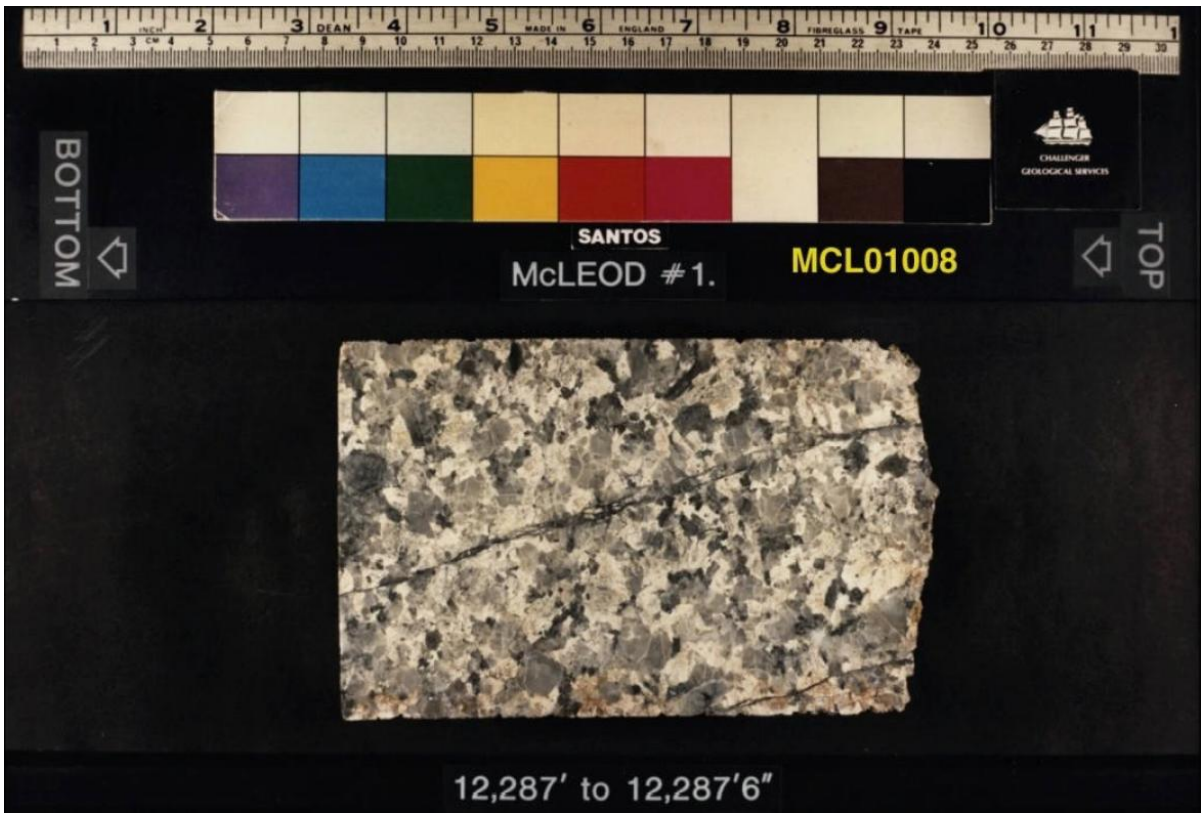


Figure 3-4: Granite core cut in McLeod 1. Steeply dipping fractures are cemented with quartz.

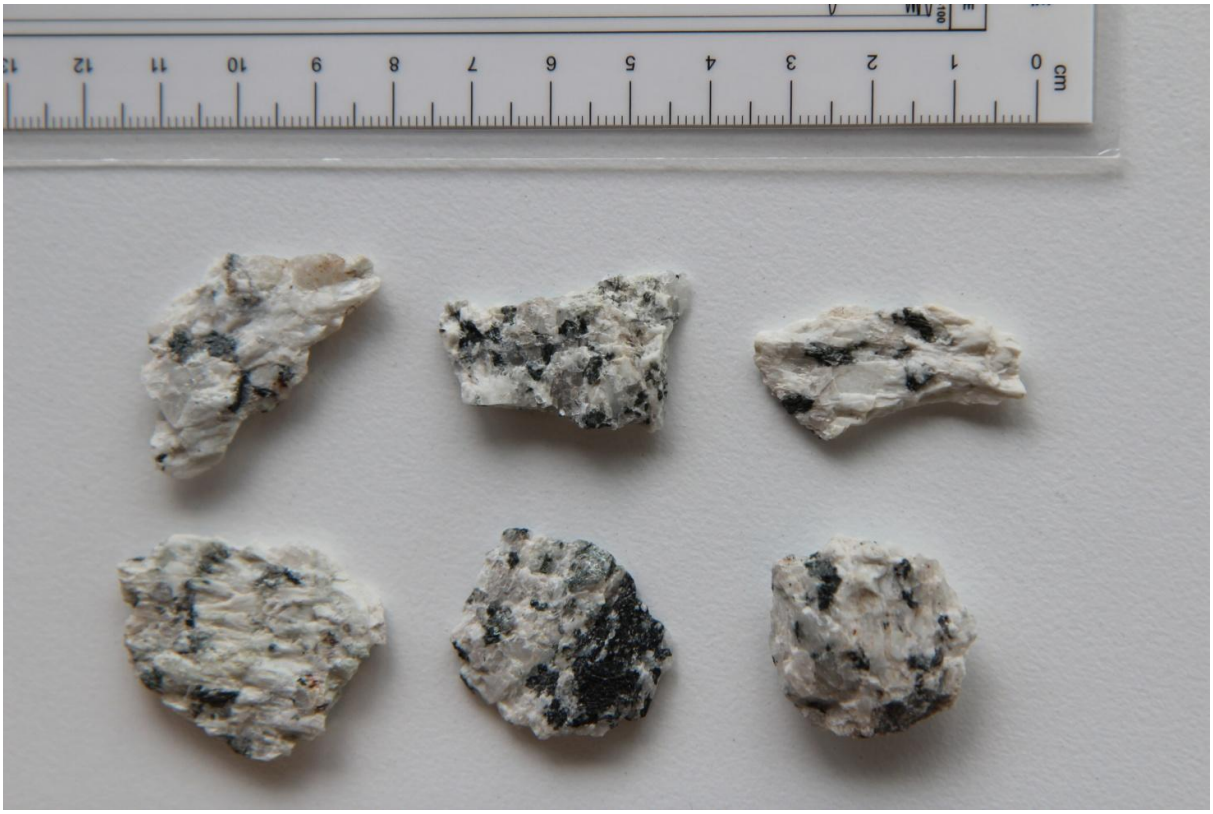


Figure 3-5: Granite cavings recovered from Habanero 4

At Jolokia the mineralogical composition of the deeper granitic rocks is slightly different. Samples from the bottom of the well (below 4,316 mSS) are showing chlorite bearing, high thorium, coarse grained granites (**Section 3.3.4**).

Porosity in the un-fractured granite has not been measured, but is not visible under a microscope so is likely to be very low. Porosity of 0.3% has been assumed.

The mineralogical composition of cuttings does not change significantly near and at the Habanero Fault intersection (Rossiter, 2008 and 2012). If there is any kind of fault gouge present then the cuttings were probably broken down during the transport to the surface.

The petrological composition of the granite has no direct impact on the reservoir but the composition and grainsize is controlling the rock mechanical properties of the granite.

3.2.2 Stress Regime

The state of stress in the Innamincka Granite has been determined from data observed by geophysical logging and drilling data analysis (Barton, 2012). This stress magnitude analysis clearly indicates a reverse faulting or over-thrust regime at reservoir depth. The azimuth of the maximum principal stress is 82 ± 5°.

The ratio of horizontal stresses to vertical stress ($SH_{max}/Sh_{min}/S_v$) is estimated to be approximately 1.35-1.45/1.10-1.25/1.0. In this over-thrust stress regime, pre-existing, N-S striking, shallow dipping structures will stimulate first. Importantly, because these shallow dipping structures are critically stressed, stimulation will occur at pressures significantly less than the overburden stress (minimum principal stress, S_v). Hydraulic stimulation causes shear failure along pre-existing weaknesses (stress sensitive fault zones) which are optimally oriented to the recent stress field rather than creating new hydraulic tensile fractures.

3.2.3 Borehole Images and Fractures

Fractures in the Innamincka Granite have been identified on acoustic borehole images recorded in Habanero 1, Habanero 3 and Jolokia 1. Fractures with similar orientations have also been identified from an electrical borehole image in Moomba 73, which penetrated the Moomba Granite, south-west of Innamincka. The fractures identified can be classified into clusters based upon their orientation (**Figure 3-6**). Two clusters of sub-horizontal fractures represent conjugate shearing related to the high horizontal stresses in the granite. These sub-horizontal fractures are critically stressed in the over-thrust stress regime and are likely to be amenable to stimulation.

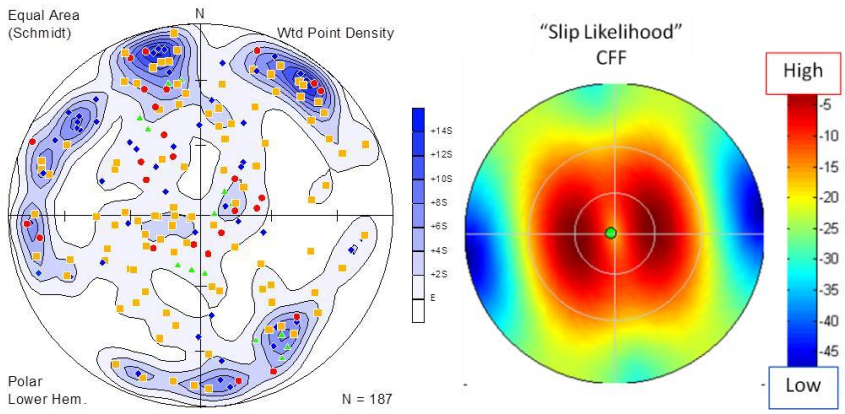


Figure 3-6: (left) Lower hemisphere Schmidt plot of fractures observed in granite sections in Habanero wells. Red symbols: high quality picks, blue: medium, orange: low. Green symbols: aplite dykes. Weighted density Terzaghi corrected for sampling bias. (right) Slip likelihood using the Coulomb Failure Function (CFF). Blue colours indicate relatively stable fracture orientations (more negative values) and red colours indicate less stable fracture orientations (more positive values)

The clusters of sub-vertical fractures present can be interpreted in different ways. They could be a classic orthogonal set of primary joints developed during the cooling phase of the granite. Typically these features form parallel and perpendicular to the maximum principal stress which was active during cooling of the granite. Alternatively, the E-W striking steeply dipping fractures might be interpreted as deformation inventory directly triggered by reactivation of thrust faults after the granite had cooled (tear faults). In either case, these sub-vertical fractures are not critically stressed in the over-thrust stress regime, so will not be likely to be amenable to stimulation.

3.2.4 Faults versus Fractures

Despite the presence of multiple fractures in various sections of the granite (**Figure 3-7**), at Habanero the vast majority of fluid flow, either into or out of the granite, occurs over a short section of intense fracturing often referred to as the "Main Fracture". This structure has been penetrated by all four Habanero wells and is now considered to be a fault (Habanero Fault) rather than a fracture zone.

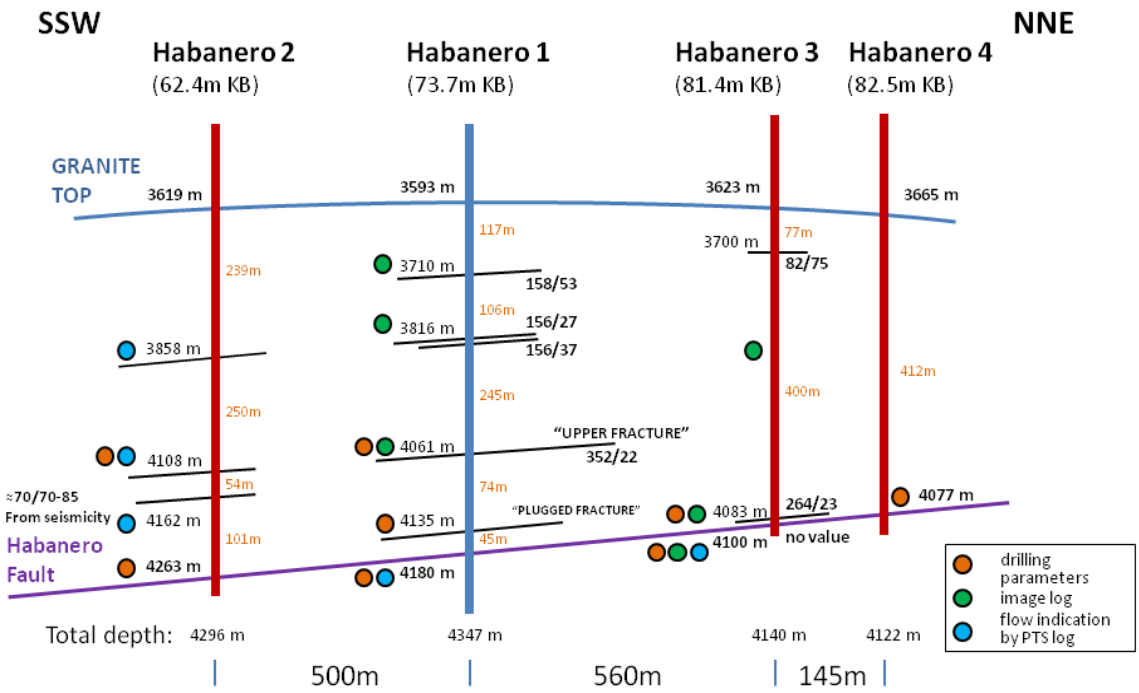


Figure 3-7: Schematic fracture distribution at Habanero, showing Habanero Fault intersected by all wells in mSS.

This fault has caused severe drilling problems in Habanero 1 and 2, resulting in kicks and mud losses whenever the bottom hole mud pressure was significantly different from the reservoir pressure within the fault. Mud weights were more closely matched with reservoir pressure in Habanero 3 and 4 and, as a result, mud losses were minimal.

The only existing image of the Habanero Fault zone was logged in H03 with a CBIL tool (**Figure 3-8**). The fault is most likely visible because the well had brine influx from the reservoir thinning the mud to a level where acoustical imaging was possible. The image above and below the reservoir decreased rapidly in quality because the barite mud system used does not allow proper acoustic imaging.

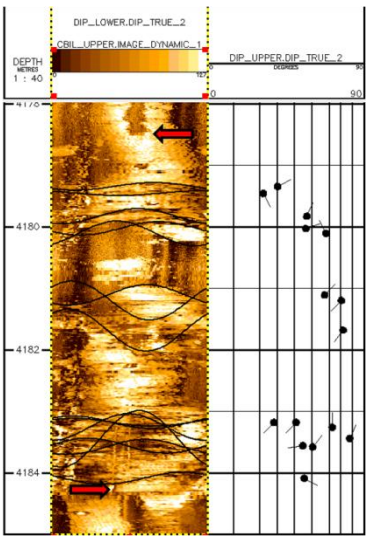


Figure 3-8: CBIL image of the Habanero Fault in H03. Red arrows are marking the top and bottom of the Habanero Fault zone. Dip and dip directions of associated fractures of the damage zone are shown in the tadpole diagram in the right track.

The image shows a 5-6 m thick fault zone which can be identified by the lack of breakout between the red arrows. Breakout is clearly developed above and below the fault zone but is absent within the fault zone due to stress release caused by slip. The major active fault plane is characterised by a 1 m thick cavern of broken out granite (4,180-4,181 mRT). Fractures above and below the active fault plane indicate the damaged zone associated with the active shear zone.

One option to produce higher quality logging data might be the use of LWD equipment if the temperature and pressure rating fit with the hostile environment of the reservoir. The main benefit would be the option to measure density, sonic or resistivity data before extensive borehole breakouts occur. This data would be more reliable than any other comparable measurement done so far. This would provide more consistent input for geomechanical calculations which is important for the stimulation design and would finally supply a better understanding of the fracture mechanics and the fault geometry of the Innamincka granite.

The field development should include at least one LWD resistivity image survey over the whole granite section to get reliable data for the modelling once. All wells should be imaged over the reservoir interval with an acoustic image log provided that a clear drilling fluid is used.

3.2.5 Induced Seismicity

In November 2012, a large hydraulic stimulation was carried out in the Habanero field. The intent of the stimulation was to expand the existing EGS geothermal reservoir and to gain a better understanding of the geothermal system, through the seismic response caused by the stimulation. The stimulation was conducted through Habanero 4, situated approximately 690 m north-east of Habanero 1, which had been used for the original stimulations in 2003 and 2005. Over 34 ML of water was injected into the existing Habanero Fault at a depth of 4,077 m total vertical depth (TVD) over a 3 week period.

During stimulation, seven seismic stations were used to transfer data in real time to the central processing office with an additional 17 stations recording in an offline mode and incorporated into the workflow in post-processing. In this three week stimulation period, over 27,000 events were recorded, of which over 20,700 events were located (**Figure 3-9**).

Averaged formal location uncertainties are 41 m, 38 m and 68 m in the east-west, north-south and vertical directions, respectively (Baisch, 2013). These uncertainty or error estimates take into account event magnitude, number of picked phases and frequency content. Event magnitudes

were calibrated against recordings from the permanent network of Geoscience Australia and were in the M_L range of -1.6 to 3.0. The hypocenter locations indicate that seismicity occurred on the same sub-horizontal structure identified in previous stimulations. The seismic cloud growth is consistent with the previous 2003 stimulation performed through the Habanero 1 well. However, it exhibits different characteristics compared to the 2005 re-stimulation through Habanero 1 where a pronounced Kaiser effect was observed near the injection well (Baisch et al, 2009).

Mapping of the induced seismic associated with the stimulations of Habanero 1 and Habanero 4 is the primary tool used to determine the extent of the Habanero reservoir. The cloud of seismic events now covers over 4 km^2. These extents were subsequently applied in the structural and dynamic modelling.

There is an apparent vertical dimension to the seismic cloud in the order of several hundred metres which is driven by the hypocentre location uncertainty. However, this is caused by uncertainty in the velocity model. The real vertical distribution of seismic events is interpreted to be a sub-horizontal layer of ~5-10 m thickness, providing further evidence of a single large fault rather than a network of fractures.

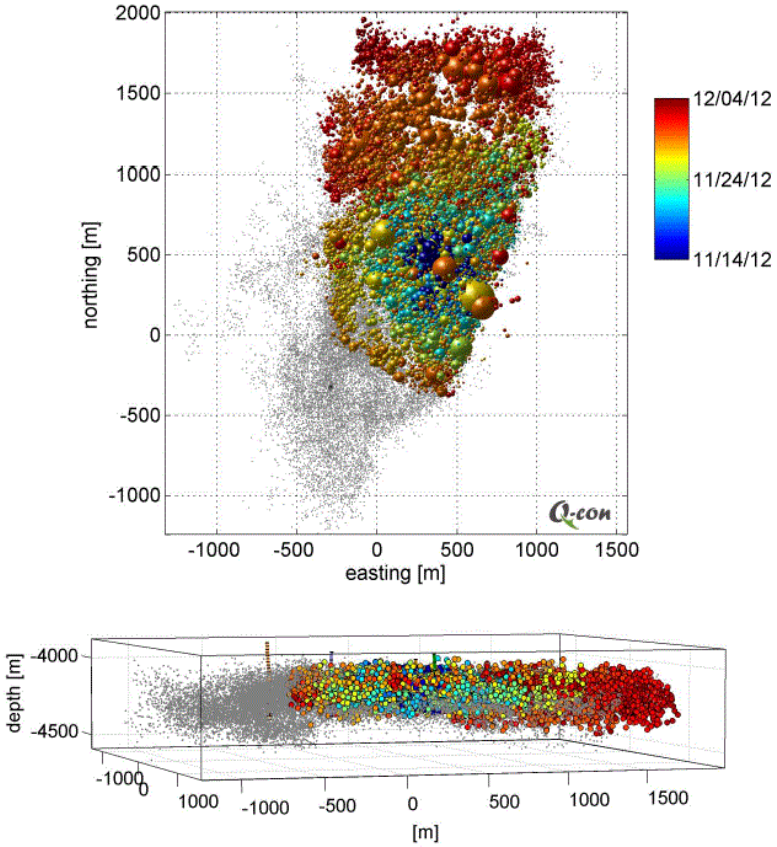


Figure 3-9: (top) Hypocenter locations of the induced seismicity from the 2012 stimulation in Habanero 4. Each seismic event is displayed by a globe scaled to the event magnitude. Colour encoding denotes occurrence time according to legend. Previous seismic activity is indicated by grey dots. (bottom) Hypocenter locations in side-view looking from ESE. Seismic events are displayed as dots with colour encoding denoting the origin time.

The seismicity from the Habanero 4 stimulation exhibits an area of reduced activity around and to the north of Habanero 1 (located at 0,0 in **Figure 3-9**). This is interpreted as an expression of the "mud ring" and has been used to guide placement of a damaged zone in the thermodynamic model.

3.2.6 Habanero Fault / Structural Model

The reservoir at Habanero is interpreted to be a fault, known as the Habanero Fault. This fault has been modelled as a planar structure, dipping at 10° to the west south west. There is some slight indication of convex downwards curvature in the seismic cloud, but this may be an artefact of the velocity model based on error margins.

Because the seismicity shows an almost linear edge along the eastern boundary of the seismic cloud (**Figure 3-9**), the Habanero Fault is interpreted to truncate against a vertical fault along that eastern boundary (**Figure 3-10**). The boundary fault has been modelled as sealing in the thermodynamic simulations because there has been very little seismicity to the east of this boundary fault. However, it is possible that the intersection of the Habanero fault and the boundary fault could have created a high transmissibility north-south channel along the eastern edge of the seismic cloud.

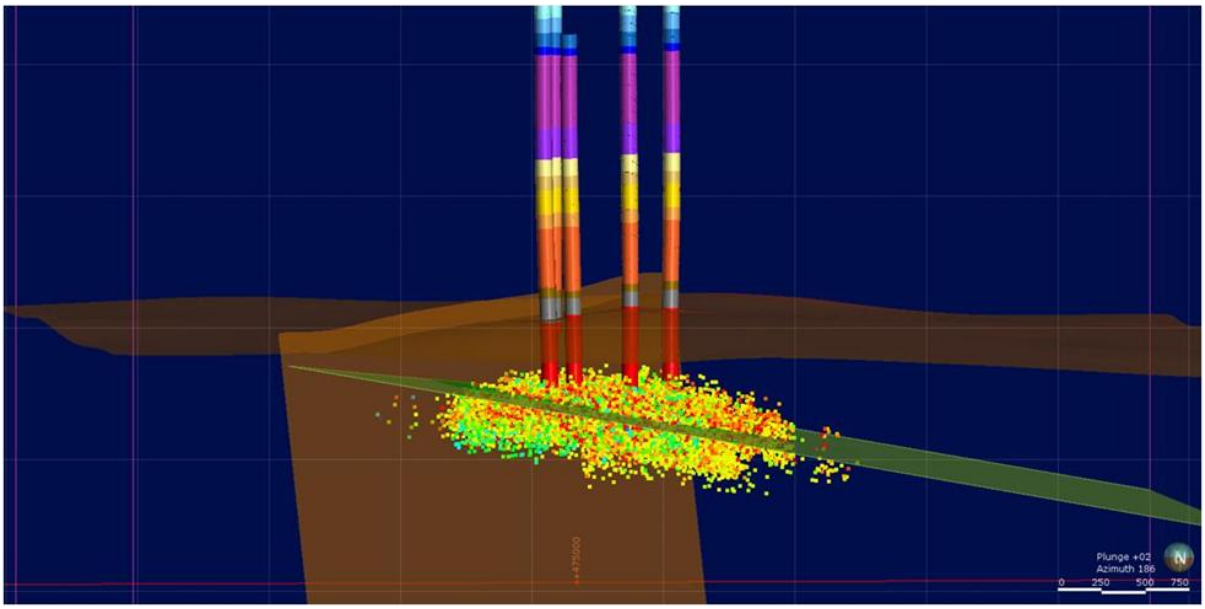


Figure 3-10: View from north looking southwards: seismic cloud (coloured dots), wells (from left to right: H04, McLeod 1 in the background, H03, H01 and H02) and the Habanero Fault (green colour). The fault dips to the west-south-west at 10° and truncates to the east against a steeply dipping fault. Top of granite is shown as brown horizon defined by well intersections (red) and seismic interpretation.

The geometry of the eastern boundary fault suggests that it was introduced as a right-lateral strike slip fault with a classical releasing bend structure (secondary fault) ca. 500 m SE of H02. This structure is unlikely to be reactivated in the recent stress field (compare **Figure 3-6**) because it would behave as a steeply dipping reverse fault (**Figure 3-11**). The reservoir might exist east of the boundary fault but does not appear to be hydraulically connected to the reservoir, presumably because of a distinct vertical offset.

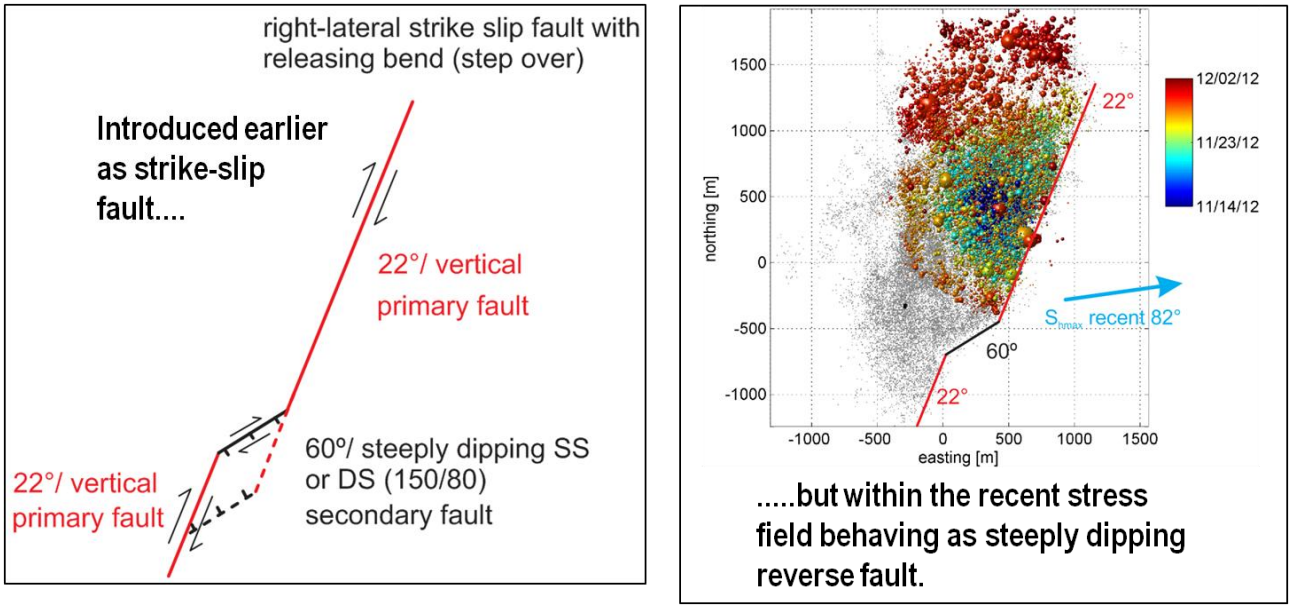


Figure 3-11: Eastern boundary fault. Interpretation of the Eastern boundary fault as right-lateral strike slip system (left figure). Mapping of the fault using all locatable seismic events (right figure).

Production and injection tests at Habanero have shown that fluid flow through the granite is controlled by the presence of pre-existing fault zones. Fractures identified by drilling parameters and image logs outside the Habanero Fault zone do not contribute significantly to production. Stimulation increases the productivity or injectivity of these faults, but they must exist already and be to some extent conductive before stimulation.

3.2.7 Likelihood of Multiple Faults

The Innamincka Granite is situated below the sediments of the Cooper and Eromanga Basins in the Nappameri Trough. The deformation history of the Nappamerri Trough is quite complex. Reactivation of pre-existing structures throughout multiple phases of structural deformation has created a complex structural inventory, particularly along the ridges bounding the Nappamerri Trough to the north-west and south-east. However, the sediments within the central Nappamerri Trough are not as severely deformed because of the rigidity of the underlying granite.

The internal structural inventory of the granite itself is not well understood and faults on top of the granite are usually identified by mapping small scale offsets of the overlying sediments using seismic data.

The Habanero Fault is most likely to have been created within the last 5-10 million years due collision of the Australian plate with the neighbouring Indonesian and New Zealand plates. However, is also possible that it might be an older structure which has been reactivated within the recent stress field (Quigley et al., 2010).

Modelling of the impact of the evolution of recent stresses upon the granite (Schrank et al, 2011) suggests that multiple faults may exist in portions of the granite. Although a shallower "upper fracture" was encountered in Habanero 2, it proved to have poor transmissibility and fault plane solutions show that it is sub-vertical rather than sub-horizontal. In effect, no wells have yet penetrated more than one hydraulically conductive fault.

3.3 Thermal Properties

3.3.1 Granite Temperatures

The best available temperature data for the Innamincka Granite are temperature logs recorded in Habanero 1 and Jolokia 1 (**Figure 3-12**). The Habanero 1 data was recorded in July 2005 after the well had been shut-in for 19 months from the end of the first Habanero stimulation in December 2003. The Jolokia 1 data was recorded on two runs of an Acoustic Formation Image Tool (AFIT) in July 2010. However, this data was recorded shortly after circulating at total depth, so is likely to be lower than the actual formation temperature.

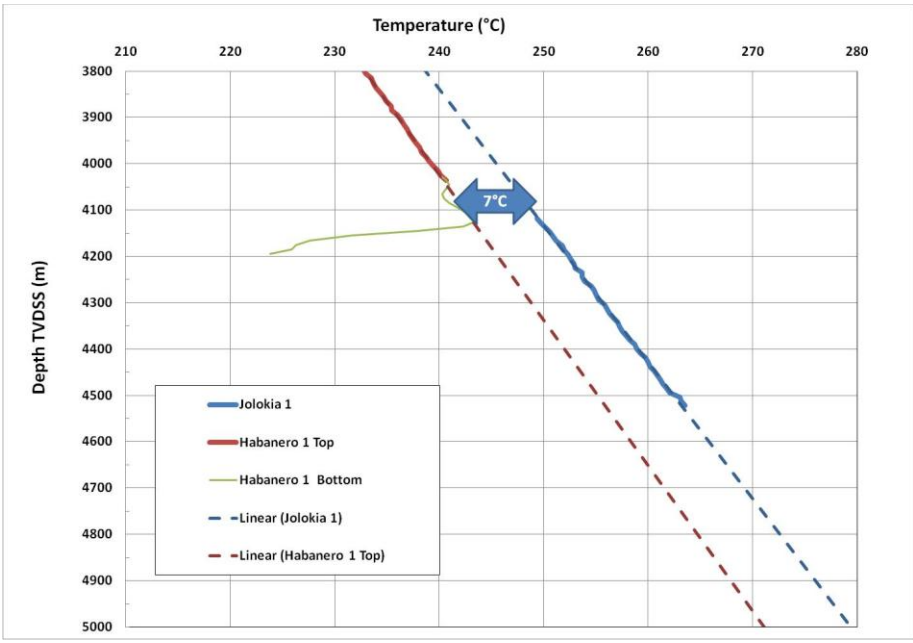


Figure 3-12: Recorded temperatures in Innamincka Granite with extrapolations to 5,000 mSS

Both the Habanero and Jolokia data sets show a linear temperature gradient of ~33°C per km but with Jolokia being ~7°C hotter than Habanero. The Habanero 1 data also shows residual cooling around the Habanero fault zone resulting from the 2003 stimulation.

The temperature gradient recorded is typical of conductive heat flow which implies that temperatures will not vary significantly across the granite. For assessment of heat-in-place, average granite temperatures have been estimated using the data recorded at Habanero 1.

3.3.2 Heat Capacity and Specific Heat

The heat capacity of the Innamincka Granite has not been measured because of the limited availability of useable core material. Heat capacity is dependent upon rock composition, temperature and the amount of water-filled pore and fracture space present within the rock. Heat capacity has therefore been estimated for a range of granite compositions, a range of porosities and a range of temperatures (Rosener, 2009).

The estimated heat capacity for the Innamincka Granite ranges from 2.55 to 2.65 MJ/(m^3.K) at a temperature of 250°C assuming porosity in the unfractured granite of 0.5%. A value of 2.6 MJ/(m^3.K) has been used for assessment of heat-in-place.

Assuming average matrix density for granite of 2,700 kg/m^3, this heat capacity converts to specific heat value of 960 J/(kg.K) which has been used in the thermodynamic model.

3.3.3 Thermal Conductivity

The thermal conductivity of the Innamincka granite has not been measured, but published values for the thermal conductivity of granite vary from 1.7 to 4.0 W/(m.K) (Reay, 2010b). Based upon 1D natural state modelling of the heat flux at Habanero (**Section 5.1.2**), a value of 3.4 W/(m.K) has been used in the thermodynamic model.

3.3.4 Insitu Heat Generation

Radiogenic heat production in granite results from the presence of varying amounts of potassium (K), uranium (U) and thorium (Th). In-situ heat production has been estimated from the chemical composition of various samples from Habanero, Jolokia and Savina (Holl, 2013). The estimates range from 3.5 to 14.4 $\mu W/m^3$, depending upon the quantities of K, U and Th present and the method of calculation. The highest values come from near total depth in Jolokia, where the granite has higher K and Th content. A heat generation value of 10 $\mu W/m^3$ has been used in the thermodynamic model.

3.3.5 Heat Flow at Habanero

Measured values of surface heat flow in the Cooper Basin region have been reported as high as 110 mW/m^2 (Beardsmore, 2004). However, in developing the thermodynamic model (**Section 5**) it was necessary to use even higher values of heat flow to match the natural state geothermal gradient. The thermodynamic model has been constructed down to 5,000 m below surface. It includes five layers to represent the top 1,400 m of granite, but the granite is believed to be 5 to 10 km thick. Heat inflow of 125 mW/m^2 has been applied to the lowermost layer of the model, representing a combination of insitu heat generation from the deeper granite and heat flow from the mantle.

3.4 Reservoir Fluid Properties

3.4.1 Brine Chemistry

Numerous brine samples have been captured at atmospheric pressure from all wells drilled so far, but most have been taken without complementary gas sampling. Matched brine and gas samples have been collected from a mini-separator during the testing of Habanero 2, Habanero 3 and Habanero 4. The most reliable analyses are considered to be those done by Geokem who preserved the samples on site to prevent precipitation as the samples cooled. The separate gas and brine analyses were recombined into "formation brine" analyses based upon the production temperature and pressure and the pressure of the mini-separator.

The composition of these matched samples has changed over time, tending towards lower concentrations of all species (**Figure 3-13**). One sample from a major brine influx (kick) at Savina 1 has been included in the plot since this appears to indicate the composition of the undiluted brine. The major changes in brine chemistry can be explained as follows:

- Habanero 2 samples gradually became less concentrated in April and May 2005 as the fresh stimulation water injected into Habanero 1 was drawn into the well;
- The September 2005 stimulation of Habanero 1 with more fresh water resulted in a step reduction of concentrations as seen in samples from Habanero 3 in March 2008;
- The blowout of Habanero 3 in April 2009 removed some of the diluted formation brine from the stimulated reservoir, drawing in less diluted brine from the surrounding granite, resulting in increased concentrations as seen in samples from Habanero 4 before stimulation;

- The extended stimulation of Habanero 4 in October 2012 resulted in further dilution of the formation brine, as seen in the most recent samples from Habanero 4.

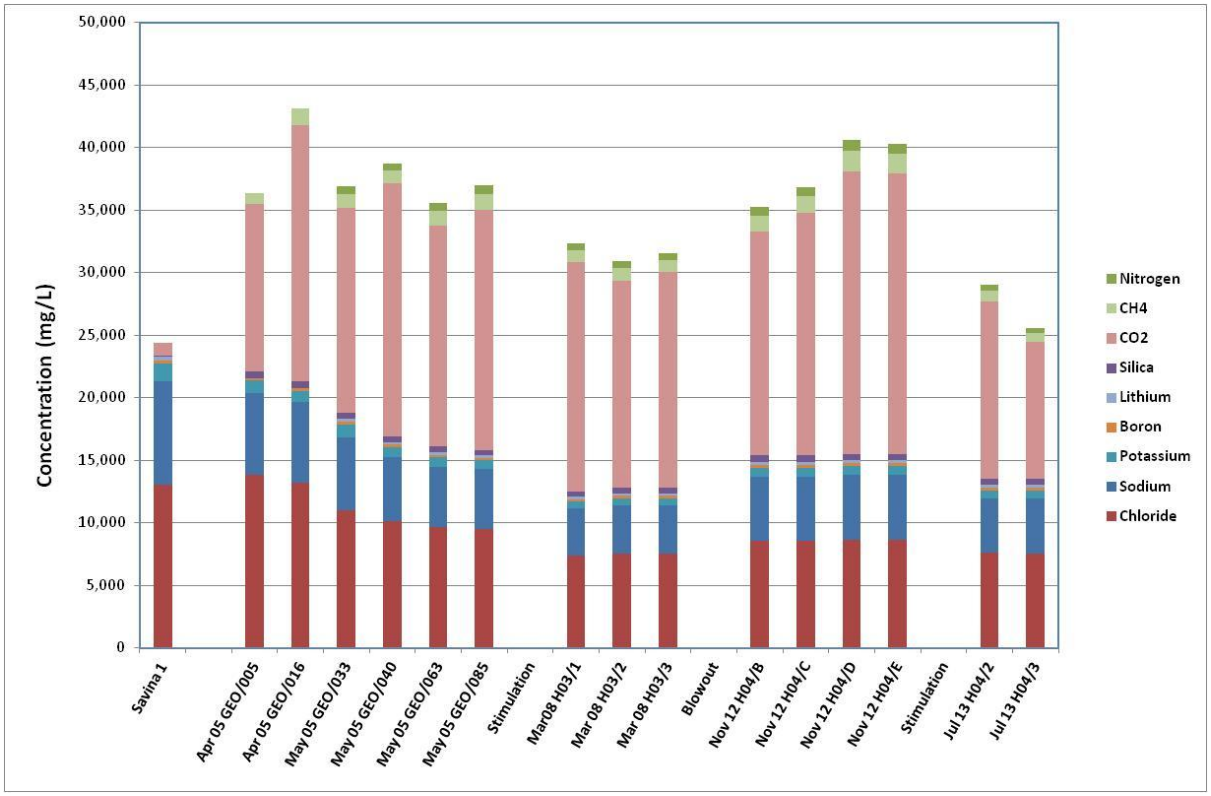


Figure 3-13: Changing formation brine chemistry over time

Whilst the Savina sample is interesting, the relevant composition for development planning is that of the most recent samples collected in July 2013 (Brown, 2013). Future production wells are likely to produce brine with similar concentrations, though the actual brine may have even lower concentrations, depending upon the amount of fresh water added to the reservoir in future stimulations. A detailed formation brine analysis is listed in **Appendix A** for planning purposes.

3.4.2 H_2S Content of Formation Brine

There has been much debate about the H_2S content of the Habanero formation brine because of the range of figures that have been reported in various analyses. Values ranging from 0.3 to 96 mg/L have been reported. It has become apparent that the magnitude of the H_2S figure reported is dependent upon the analysis method used. In particular, all the high figures have resulted from the iodometric titration method, which is not specific for H_2S and will detect any species which will oxidise iodine. Consequently, the Habanero 4 samples have all been analysed using both the iodometric titration method and the H_2S-specific methylene blue method.

The methylene blue method has given results in the range 0.3 to 15.3 mg/L of H_2S. The highest value, 15.3 mg/L, was recorded from the most recent Habanero 4 samples and is considered to be the real concentration.

As expected, the iodometric titration method gave higher readings. The identity of the gas which reacts with iodine but is not detected by methylene blue remains unknown. Gas samples have been sent to several laboratories, but so far none of the analyses have returned a positive identification.

3.4.3 Brine PVT Properties

Two pressurised, bottom hole brine samples were captured in Habanero 4 in purpose-built, Titanium alloy, sample chambers. One of these samples was used for compositional analysis and the other was used for PVT analysis. Two constant composition expansion experiments were done at 100°C and 200°C (Core Laboratories, 2013).

At 200°C, the measured brine compressibility was 5.4×10^{-7} kPa^{-1} (3.7×10^{-6} psi^{-1}) which is in line with, but less than, expected for pure water under reservoir conditions.

Bubble point pressures were measured as 13.1 MPa at 200°C and 12.4 MPa at 100°C. These results show that it is highly unlikely that free gas will be encountered anywhere within the pressurised surface equipment. However, in the event that the pipe work is depressurised at temperatures below boiling point, the gas-water ratio is ~9.4 m^3/m^3, so substantial volumes of gas, mostly CO_2, will be liberated. If depressurisation occurs at temperatures above boiling, then steam generation will increase the gas-water ratio.

3.5 Heat in Place Estimate

An assessment of geothermal resources in the whole Innamincka Granite (Hogarth, 2013) has been prepared in accordance with the Australian Code for Reporting of Exploration Results, Geothermal Resources and Geothermal Reserves, Second Edition (2010), more generally known as The Geothermal Reporting Code.

An area of 16 km^2 around Habanero can be considered a Measured Geothermal Resource under The Geothermal Reporting Code. Across this area, the Habanero Fault is expected to be encountered at depths between 3,787 and 4,751 mSS. However, the developments outlined in this FDP would only access the 4 km^2 area of the existing seismic cloud. Consequently, heat in place has been estimated for both the 16 km^2 measured geothermal resource area and the 4 km^2 seismic cloud area, as shown in **Table 3-1**.

A cut-off temperature of 180°C has been used for geothermal resource assessment. This temperature represents the average temperature of the granite after production of geothermal energy, recognising that actual rock temperatures will be cooler around the injection wells and hotter around the production wells.

Table 3-1: Habanero Heat in Place Estimate

Parameter	Units	Seismic Cloud Area Only	Measured Geothermal Resource Area
Area	km^2	4	16
Depth range	m	4,000-4,500	3,700 – 4,800
Thickness	m	500	1,100
Volume	km^3	2	17.6
Average temperature	°C	243	247
Cut-off temperature	°C	180	180
Heat Capacity	$MJ/(m^3.K)$	2.6	2.6
Heat in Place	PJ_{th}	330	3,100

4. DYNAMIC RESERVOIR DATA

4.1 Well Test Data and Analysis

4.1.1 Static Conditions

An arbitrary reservoir datum depth has been established at 4,140 mSS, approximately the depth of the Habanero Fault half-way between Habanero 3 and Habanero 1. Static bottom hole conditions at this datum have been estimated from pressure build-up tests conducted in Habanero 3 and 4. The static datum conditions are 244°C and 73 MPa.

Static surface conditions have been measured with a production log recorded in Habanero 1 in 2005 after 19 months shut-in. The shut-in wellhead pressure (SIWHP) is 33.7 MPa with water in the well.

4.1.2 Production Tests

Production tests have been conducted on three Habanero wells: Habanero 2, 3 and 4. However, the tests on H02 were affected by the presence of a bridge plug stuck in the open hole so these results are not considered representative and have been excluded from further analysis.

All the production tests have been conducted with relatively short periods of constant mass flow rate. Stable flowing conditions were rarely reached for any of these tests because of the limited volume of the reservoir and the temperature transients affecting fluid density in the well bore. All downhole pressure data has been corrected to the datum depth assuming a column of brine in the well.

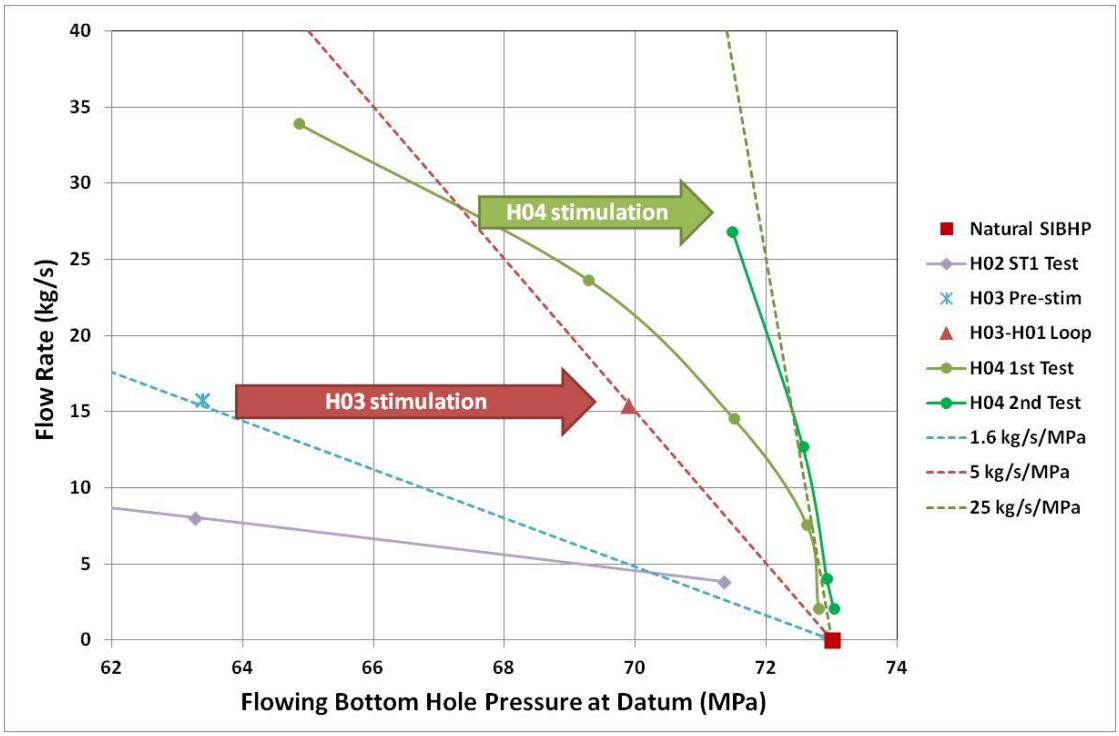


Figure 4-1: Production flow rate versus flowing bottom hole pressure, showing stimulation effects.

Production logs have been recorded during five production tests so far at Habanero (**Figure 4-1**). Two single-rate production tests were done at H03: one before stimulation, and; the second after a relatively small "local" stimulation, recorded at the end of the H03-H01 closed-loop. Comparison of the flowing pressures from these two tests shows a three-fold increase in bottom hole productivity from 1.6 to 5 kg/s/MPa after the stimulation.

Three multi-rate tests were done at H04, though only the first and second were run with downhole gauges. The first multi-rate test, done before stimulation, showed very high productivity at low rates, but a distinct reduction of productivity at higher rates. This result suggested that some turbulent flow was occurring near the well bore, especially at higher flow rates.

The second multi-rate test, done after local stimulation, showed a significant increase in productivity at higher flow rates, with an almost linear response at ~25 kg/s/MPa, suggesting that turbulent effects are minimal within the range of test rates. This test also confirmed the finding from H03 that relatively small, local stimulations are effective for reducing near well bore impedance.

Surface production data at Habanero (**Figure 4-2**) show the form of productivity relationship typical of geothermal wells. Production at relatively low rates is at flowing well head pressures greater than the natural SIWHP. This is because the relatively cooler and heavier brine in the shut-in well is replaced with hotter and lighter brine during production.

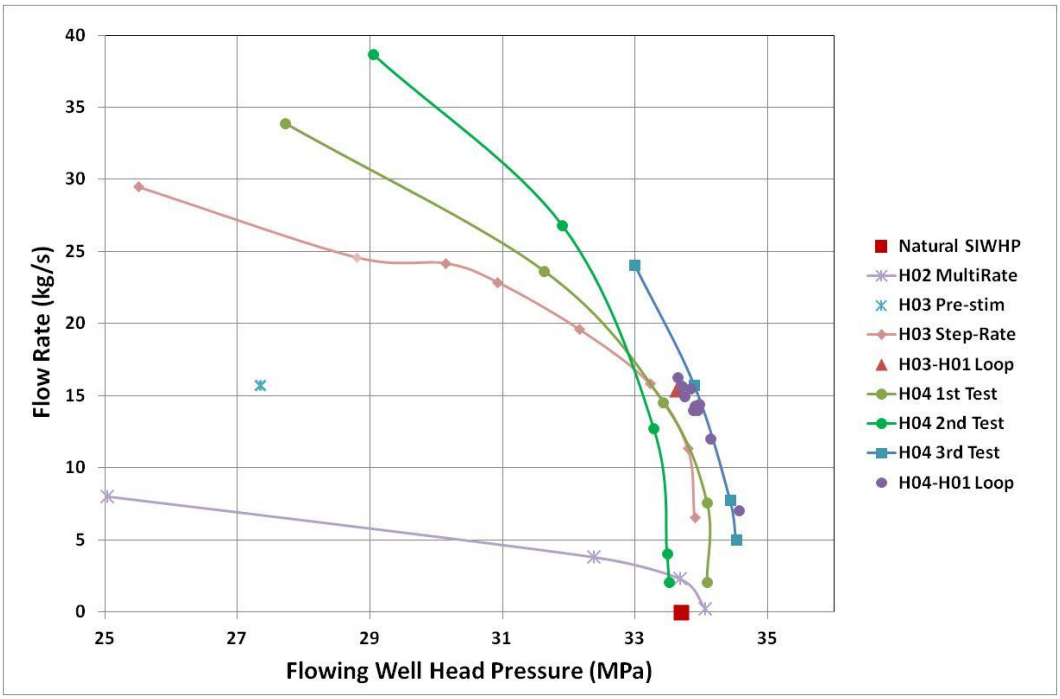


Figure 4-2: Production flow rate versus flowing well head pressure for all Habanero tests.

The first reliable production test was a step-rate test done at H03 after completion of closed-loop testing in 2009. The results (**Figure 4-2**) show a distinctly curved trend, suggestive of turbulent effects somewhere in the system. A maximum rate of 29 kg/s was achieved.

The first multi-rate test at H04, done before stimulation, shows improved productivity in comparison to H03, though again with some evidence of turbulent flow. The second and third multi-rate tests demonstrate clearly the benefits of stimulation, with reduced turbulent effects and productivity improving markedly after both stimulations.

The second test concluded with a high rate period where a maximum rate of 39 kg/s was recorded. From the limited drawdown at this high rate, it is clear that higher rates could have been achieved, but the test was constrained by the flow metering capability.

4.1.3 Injection Tests and Stimulation

Hydraulic stimulations have been conducted in all four Habanero wells, and Jolokia (J01). These hydraulic stimulations have by-and-large been done with fresh water without additives, though some NaCl saturated brines were used during early stimulation of H01. A summary of all the Habanero stimulation volumes is provided in **Table 4-1** below.

Table 4-1: Summary of Habanero stimulations and volumes

Stimulation	Date	Volume (ML)
H01 (2003)	Nov-Dec 2003	20
H02 (2005)	Jul-Aug 2005	3.8
H01 (2005)	Aug-Sep 2005	17
H03 (Local)	Apr 2008	2.2
H04 (Local)	Oct 2012	2.5
H04 (Extended)	Nov 2012	34

The sub-horizontal oriented Habanero fault is critically stressed in the recent over-thrust stress regime and is very sensitive to stimulation. Downhole stimulation pressures based on first occurrence of seismicity and/or pressure drop measured during stimulation are summarized in **Figure 4-3**. It is clearly shown that the "activation" pressures of the Habanero Fault are generally below the overburden stress (compare chapter 3.2.2). Only the H02 and J01 activation pressures are much higher because the steeply dipping structures encountered in these wells are unfavourable oriented for slip in the recent stress field.

In case of the H04 stimulation, seismic activity started after increasing the downhole pressure by only 2.6 MPa during the local stimulation and even less ($\Delta p \sim 0.4$ MPa) during the extended stimulation. **Figure 4-3** also shows the estimated downhole pressure when stimulating with a surface pressure of 7,000 psi (48.3 MPa), assuming water in the well. The estimated downhole pressure is in this situation would be at least 5 MPa (725 psi) above the pressure at which first seismicity was achieved on all earlier stimulations. Based upon this, a maximum surface pressure of 7,000 psi (48.3 MPa) has been used in the well designs as sufficient for stimulation pressures of an undamaged Habanero reservoir.

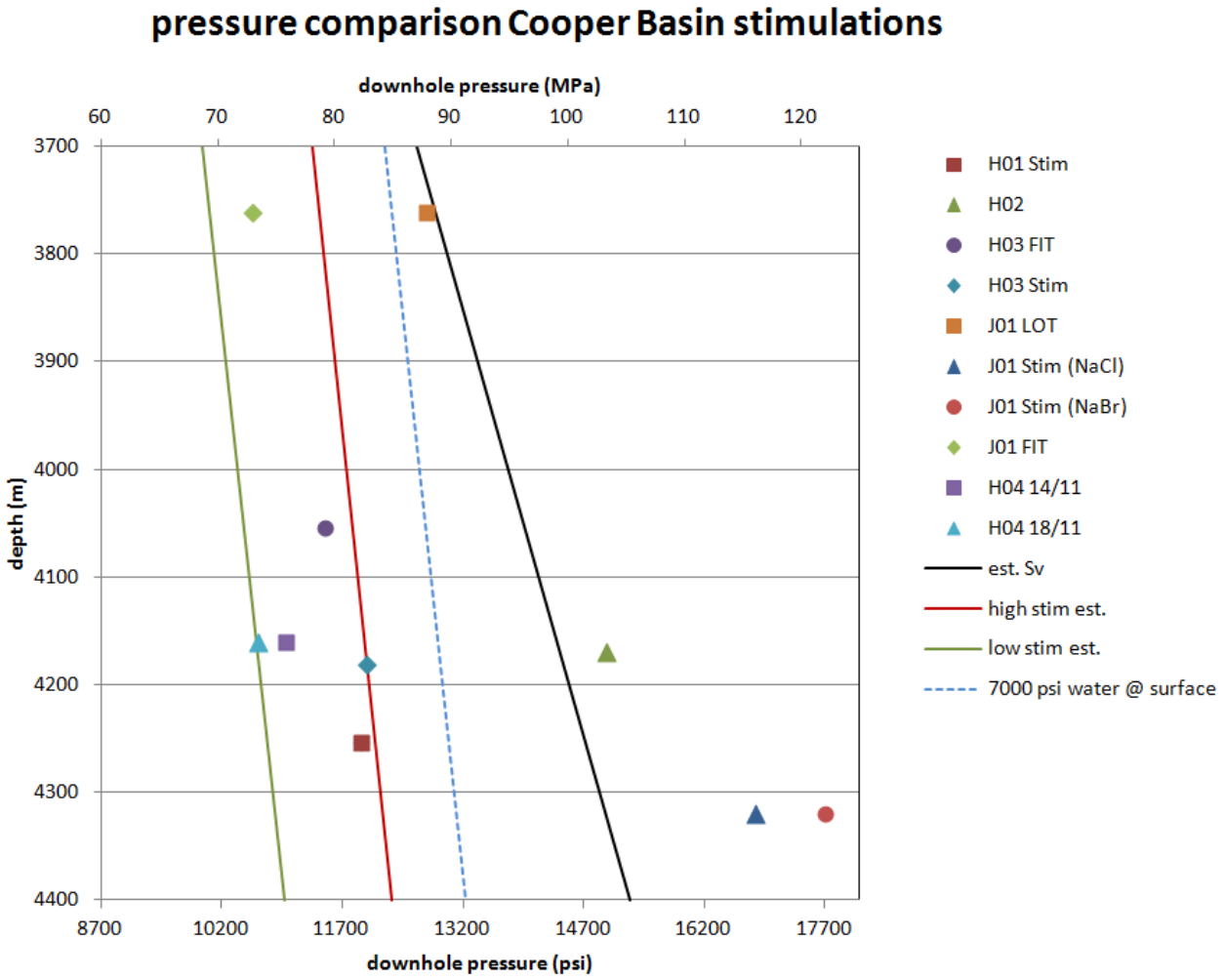


Figure 4-3: Downhole pressure comparison for Cooper Basin operations. All available pressure values within the Innamincka granite (LOT, FIT, pressure @ first slip) are plotted versus depth. Green and red lines delineate a low and high pressure estimate for activation limits of slip of the critically stressed Habanero fault. Blue dotted line shows a water pressure gradient with 7000 psi (48.3 MPa) at the well head. Overburden stress (minimum principal stress) is shown by the black line.

Production logs have been recorded during three of the stimulations performed so far (**Figure 4-4**). Data from the two major stimulations of H01 show bottom hole injectivity of only ~1 kg/s/MPa, despite the large volumes of water injected during stimulation. During drilling of H01 approx 250 m^3 (1,600 bbl) of 1,800 kg/m^3 (15 ppg) mud was lost into the Habanero Fault. This lost drilling mud is believed to have created a zone of reduced permeability around H01, termed the "mud ring", where mud solids, particularly barite, have settled out in the fractures that make up the fault (Chen, 2010).

By the end of the H03-H01 closed-loop test (refer **Section 4.1.5**) bottom hole injectivity in H01 is estimated to have improved to ~1.6 kg/s/MPa, though no downhole gauges were run to validate this estimate.

Bottom hole injectivity at H04 was ~4.5 kg/s/MPa during the local stimulation, which is a significant improvement in injectivity. Note that the bottom hole injectivity of both wells (H01 and H04) is more or less linear, showing no impact of turbulence which might be expected to occur near the well bore, especially at higher rates.

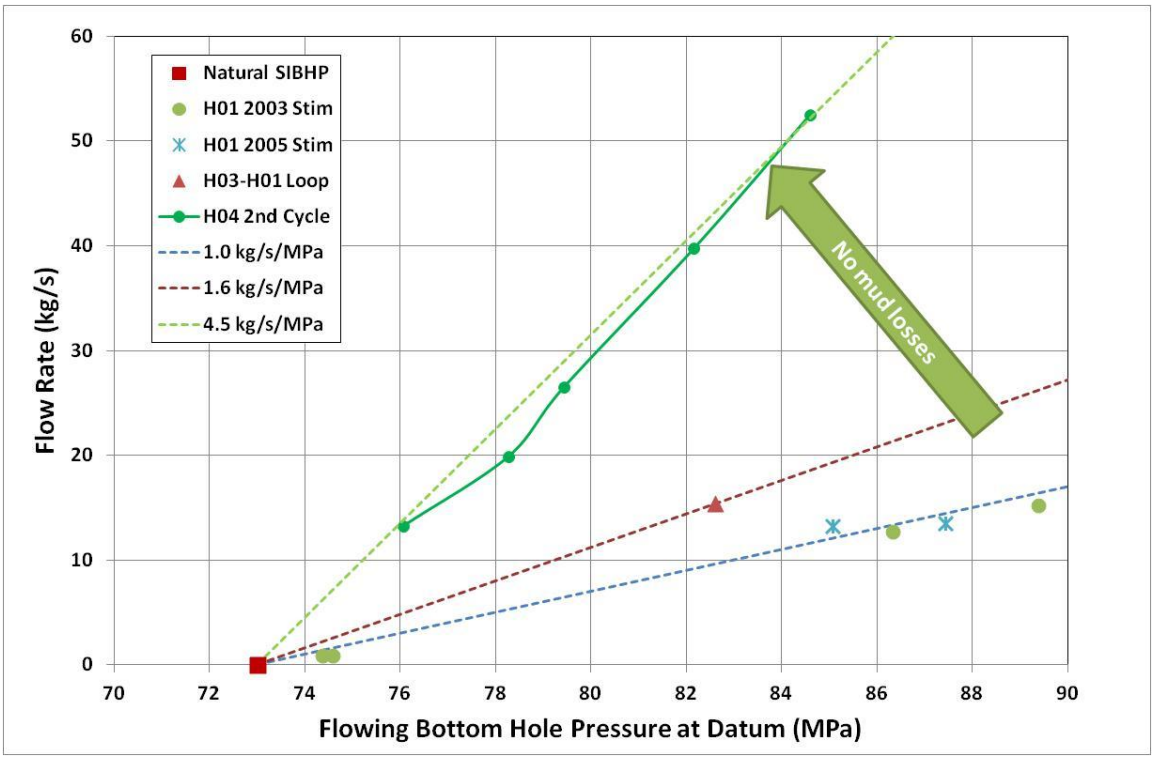


Figure 4-4: Stimulation flow rate versus flowing bottom hole pressure showing impact of mud losses.

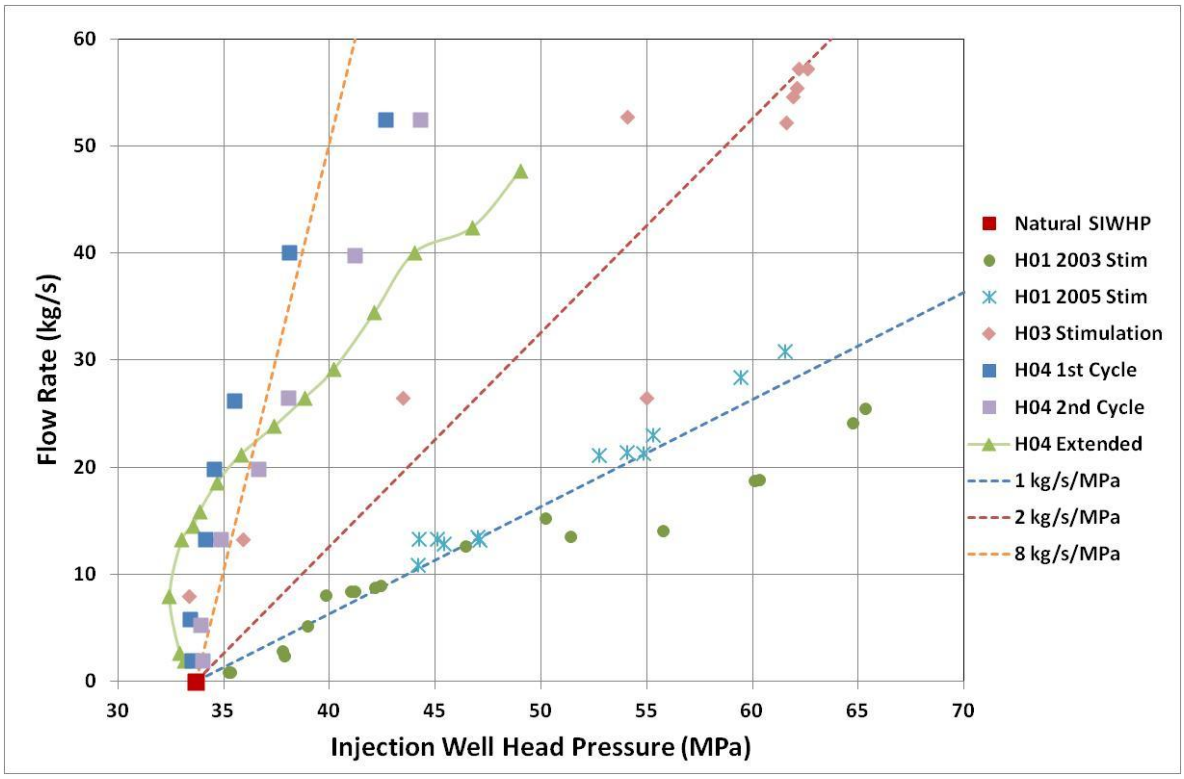


Figure 4-5: Stimulation flow rates versus surface injection wellhead pressures

The surface data from the Habanero stimulations (**Figure 4-5**) shows clearly how poor the injectivity is at H01. Despite having injected approx 33 ML of stimulation water, injectivity remained

at around 1 kg/s/MPa. However, injectivity at H03 was significantly better, averaging ~2 kg/s/MPa at high injection rates and better still at lower rates.

H04 was stimulated twice: once with a small volume, local stimulation and then with a large volume, extended stimulation. The well achieved very high injectivities of 8-16 kg/s/MPa. For the final, extended stimulation, it is notable that a temperature-density effect is evident, with low rate injection occurring at pressures below the static shut-in pressure because the well has been filled with cold, dense stimulation water.

4.1.4 Closed Loop Tests

A closed-loop test involves connecting two (or more) wells in a loop such that the total mass flow from the production well is re-injected into the injection well. There are no losses in the Habanero closed-loop: production mass rate is equal to injection mass rate. At Habanero, because of the high overpressure in the reservoir, the brine remains in single phase throughout the loop, without boiling or losing any of its dissolved gases. A brine re-injection pump on surface is used to re-pressurise the brine so that it can be re-injected.

The first closed-loop test was between H03 and H01, located 570 m apart. Over a period of 71 days from December 2008 to February 2009, a total of 61,000 tonnes of brine was circulated between the wells. Because of system constraints, the loop was operated within a narrow range of circulation rates from 13 to 15 kg/s. The maximum flowing temperature was 212°C and the maximum circulation rate achieved at the end of the test was 15.4 kg/s.

The second closed-loop test was between H04 and H01, located 690 m apart. Circulation commenced in April 2013 and over a period of 161 days until October 2013, a total of 182,000 tonnes of brine was produced from H04. Most of this brine (91%) was re-injected into H01 and the balance was open flowed into storage dams. The maximum flowing temperature was 215°C and the maximum circulation rate achieved was 18.9 kg/s.

4.1.4.1 Flowing Temperatures

Because the granite is deeply buried, there is ~4,200 m of borehole to heat in the production well and the same length of borehole to cool in the injection well. The impact of these long boreholes is a long, slow build-up of flowing temperatures over time, particularly at lower flow rates. **Figure 4-6** shows the build-up of temperatures in H03 and H04 versus cumulative mass flow from the production well. Both tests show a continuing trend towards higher temperature even at the end of long periods of stable flow.

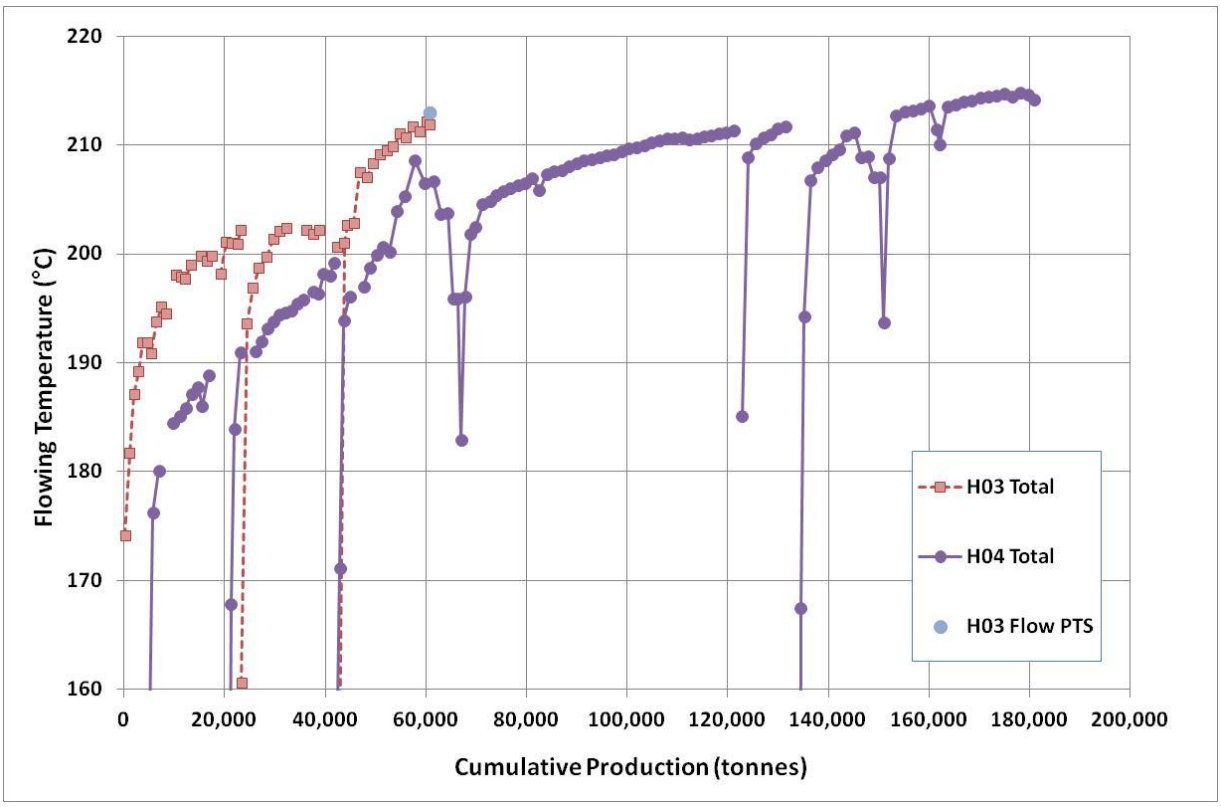


Figure 4-6: Flowing well head temperature versus cumulative production from H03 and H04

The lower temperatures at H04 are a result of the stimulations in October 2012 which placed 36.5 ML of cool water into the Habanero Fault. Some of this temperature drop has been recovered over time, but slowly. A production log run at the end of the H04 closed-loop recorded flowing bottom hole temperature of 236°C, still five degrees less than the flowing bottom hole temperature recorded before stimulation. The lesson to be taken from this finding is that future production wells should not be subjected to massive stimulations.

Fortunately, the slow build-up of wellbore temperature also means that wellbore temperatures drop slowly during shut-ins. The plot shows that temperatures return to trend quickly after shut-ins.

The temperatures recorded at H04 have been used to calibrate a WellCAT model to provide estimates of flowing well head temperatures at various flow rates (**Section 5.5**).

4.1.4.2 Loop Performance

Performance of the sub-surface portion of the closed-loop has been assessed by considering the pressure difference between the two well heads. **Figure 4-7** presents a plot of closed-loop circulation rate versus that well head pressure differential.

The H04-H01 loop has been operated at a wide range of flow rates so that the performance relationship (or system curve) can be characterised. The loop has even been operated at very low

rates where the well head pressure differential was close to zero. These tests have allowed determination of the thermosiphon effect (or buoyancy drive). For a test done early in the closed-loop trial (1st Step Test), the thermosiphon effect provided a flow rate of ~5.5 kg/s, driven entirely by the density difference between hot and cold water.

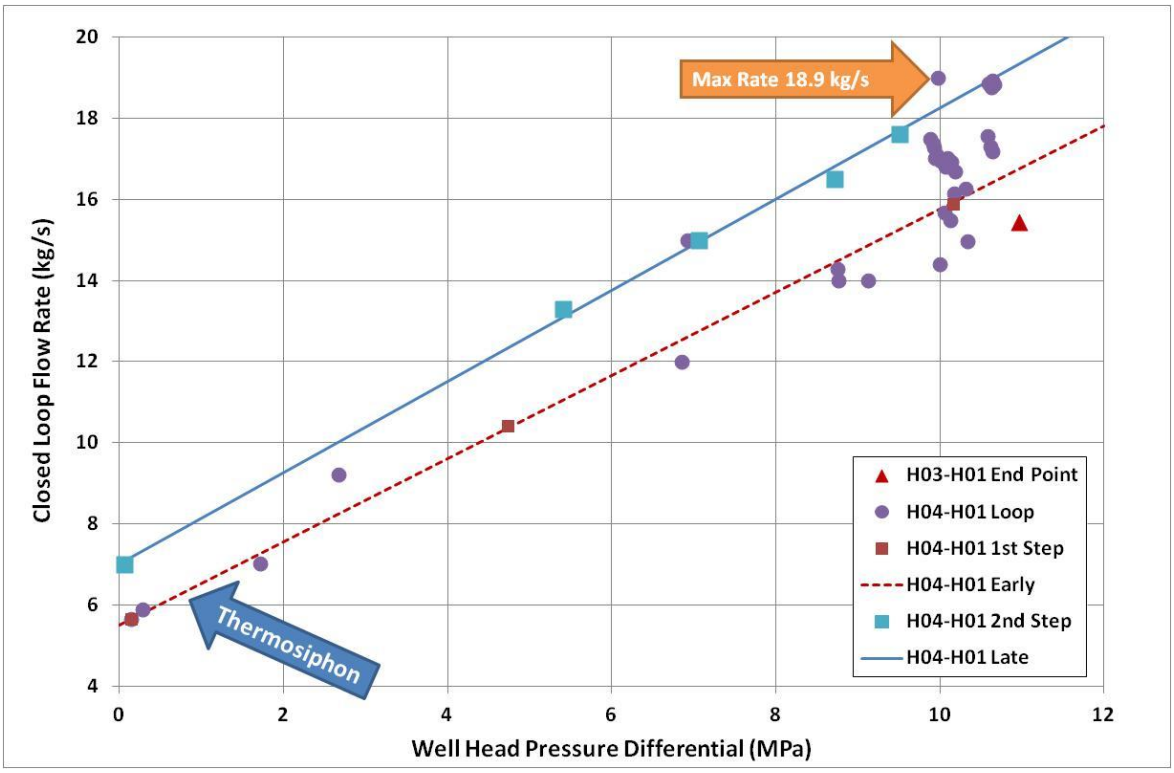


Figure 4-7: Loop chart showing closed loop flow rate versus well head pressure differential.

Later in the closed-loop trial, a 2nd Step Test showed that the impedance within the reservoir had reduced (**Figure 4-7**) and that the thermosiphon effect was now driving a flow rate of ~7 kg/s. Examination of the performance of both wells shows that the changes which are causing this improvement are occurring entirely at H01. The most likely explanation is that this change is a result of progressive dispersal of the mud solids blocking the fault as re-injection continues.

4.1.5 Productivity Forecasts

From the closed-loop flow tests it is clear that the performance of a closed-loop depends not just upon the performance of an individual well, but upon the performance of the complete system i.e. the reservoir, the two wellbores and the surface pump. A convenient way to look at this is to combine the performance characteristics of the producer, the injector and the pump into one plot.

Figure 4-8 is a plot of the mass flow rates versus flowing well head pressure showing both H01 and H04 data in the recent closed-loop test. From this “Vee” plot it can be seen that the flow performance of H04 in closed-loop mode follows parallel to the post-stimulation production test results. However, flowing pressures are slightly higher than in open flow testing, most probably because of the pressure support from re-injection at H01.

Similarly, the injection performance of H01 in closed-loop mode follows parallel to the stimulation injection performance. Again, the closed-loop injection pressures are slightly lower than during stimulation, most probably because of the pressure drawdown from production at H04.

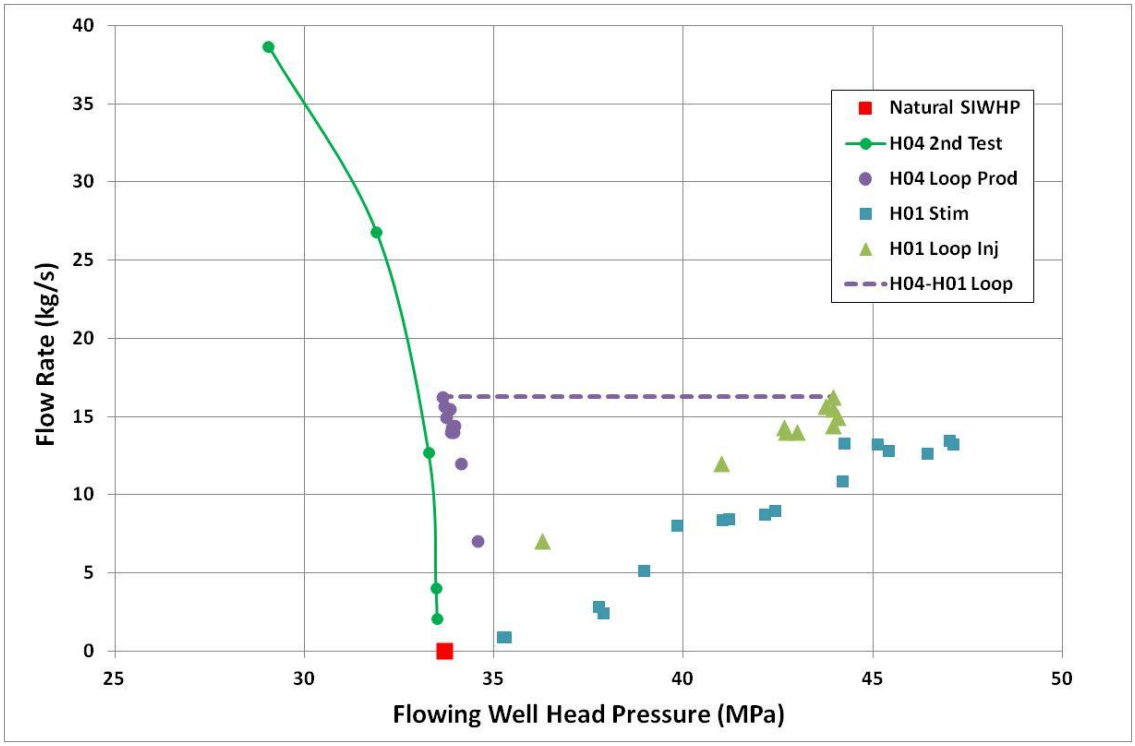


Figure 4-8: "Vee" chart showing closed-loop flow rates versus flowing well head pressures for H04 and H01. The "H04-H01 Loop" line shows the well head pressure differential as at end July 2013.

If a closed-loop were established with two wells like H03 where injectivity is significantly higher, then greater closed-loop flows could be achieved. **Figure 4-9** (left) shows the production test and stimulation performance curves for H03. With a well head pressure differential of 10 MPa, then closed-loop flow rates of ~25 kg/s could be achieved.

If a closed-loop were established with two wells like H04, where injectivity and productivity are higher still, then significantly greater closed-loop flows could be achieved. **Figure 4-9** (right) shows the production test and stimulation performance curves for H04. With a well head pressure differential of 5 MPa, then closed-loop flow rates of ~25 kg/s could be achieved. Allowing a well head pressure differential of 11 MPa, then closed-loop flow rates of up to 40 kg/s could potentially be achieved.

Based upon this analysis of closed-loop flow performance, an average brine rate of 35 ±10 kg/s has been assumed for each production or injection well. In the thermodynamic simulations, each reservoir scenario was set up assuming 35 kg/s (~19,000 bbl/d) flow per well. Sensitivities were then run with the same well layout but with 25 or 45 kg/s per well.

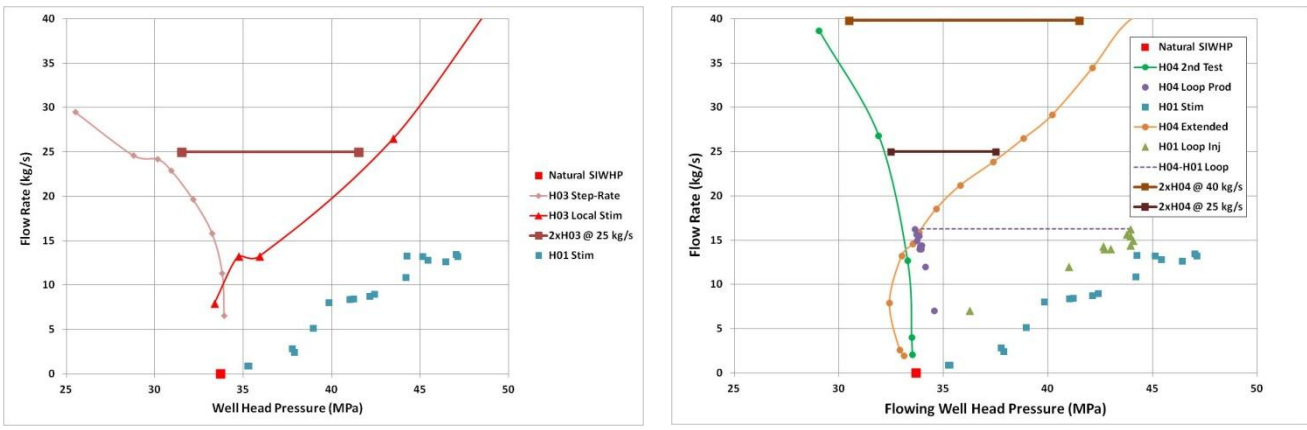


Figure 4-9: "Vee" chart showing potential closed-loop flow rates versus flowing well head pressures for two wells like H03 (left) or two wells like H04 (right).

The surface brine piping layout proposed will have a common production header pressure for all production wells and a common injection header pressure for all injection wells. Consequently, the performance of each well is governed by the overall system performance, not just the performance of another single well. To assess the potential ranges of closed-loop flow rates, the 25-35-45 kg/s flow range for a pair of wells was converted into effective productivity and injectivity indices. These indices were used in a Monte Carlo analysis to estimate the potential range of flow rates from four wells and from six wells (**Figure 4-10**).

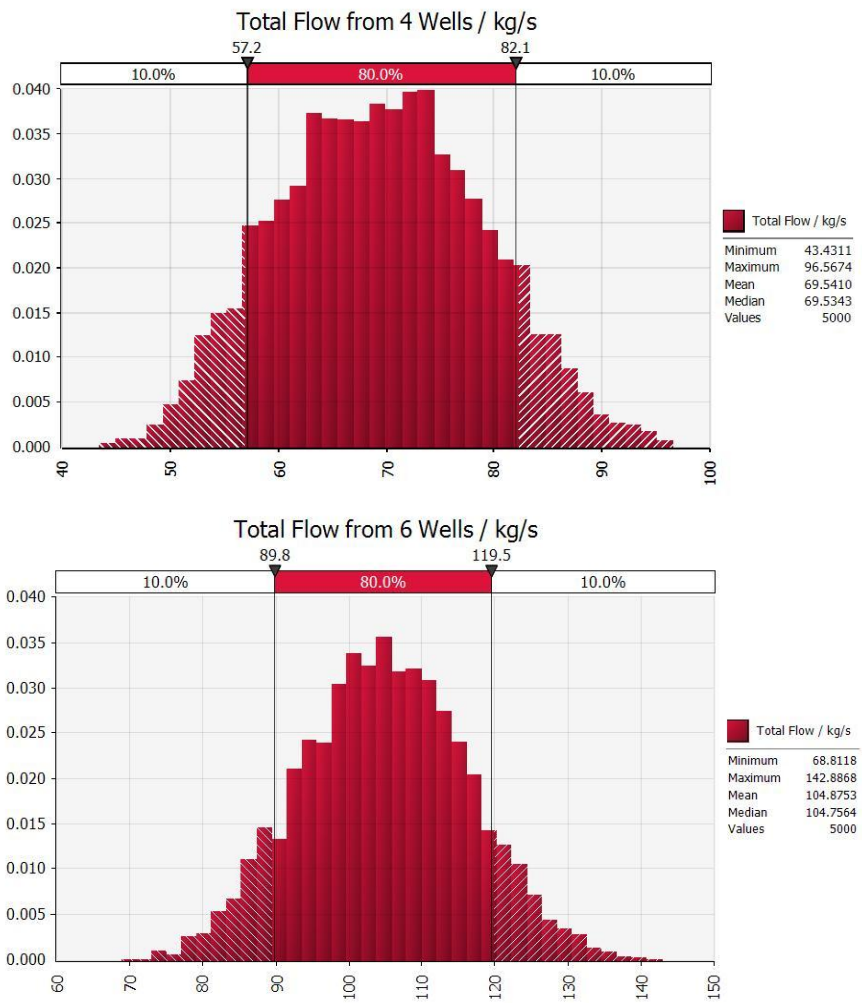


Figure 4-10: Probabilistic assessment of potential flow rates from 4 wells (top) and 6 wells (bottom)

4.1.6 Pressure Transient Analysis

Obtaining reliable pressure transient data has proven difficult at Habanero. In production wells, because of the high reservoir temperature, even pressure gauges housed in a Dewar flask are generally only able to record data for 6-8 hours. In injection wells, the temperatures are lower so recording times are longer, but the thermal transient as the well bore warms up makes the normal pressure transient hard to characterise. In addition, the wellbore generally behaves as a very "hard" system which generates fluid hammer whenever flow control valves are opened or closed. In one injection test at H01 on 24 Aug 2005, a downhole spinner tool recorded flow oscillating between upward and downward during the early-time fluid hammer phase. Nevertheless, numerous pressure transients have been recorded and analyses have been attempted by various investigators (Reay, 2009).

The earliest tests were fall-off tests conducted at the beginning of the 2003 stimulation of H01. Although these analyses are based only upon surface data, they provide the best available transient data for the unstimulated fault. The various estimates range from 15 to 86 mD.m. Interestingly, all the analyses of the H01 data interpret negative skin, which suggests an increase in transmissibility near the wellbore. Thus the data suggests that immediately around the H01 wellbore, the fault zone is not blocked by mud solids, despite the likely presence of a mud ring. An analysis of pressure surges in the Habanero 3-1 closed loop trial (SVT, 2011) found that, in order to model the observed system behaviour, it was necessary for "the injection well to contain a large volume of pressurised fluid", in addition to the contents of the wellbore itself. This model result again suggests that the fault zone immediately around Habanero 1 is open and unblocked.

The blow-out of Habanero 3 and the subsequent pressure recovery provided another source of data from which to estimate the properties of the unstimulated fault area. A material balance model of the fault (Reay, 2010) was constructed with two interconnected tanks representing the stimulated and the unstimulated fault areas. From this model it was estimated that the unstimulated fault had transmissibility of between 40 and 80 mD.m. A value of 50 mD.m has been used in the thermodynamic model.

Pressure build-up and interference tests at H03 provide the earliest assessment of transmissibility for the fault zone after stimulation. The various estimates range from 160 to 3,000 mD.m depending upon the model used and assumptions made.

Perhaps the best controlled of the transient tests done so far were two modified isochronal tests conducted at H04, before and after stimulation. Analysis of these two tests (Davidson, 2013) show that transmissibility improved from ~5,300 mD.m with positive skin before stimulation to ~10,000 mD.m and zero skin after stimulation. A value of 10,000 mD.m was used for the stimulated fault to initialize the thermodynamic model, but this was subsequently reduced during the model calibration process (**Section 5.2**).

The only test of the granite without a fault is the early injectivity testing of Jolokia 1. Whilst injectivity for this test was extremely poor, the data has been interpreted (Jung, 2013) to show natural state transmissibility of ~0.0003 mD.m over 591 m of open hole section. This is equivalent to natural state permeability for unfaulted granite of 0.5 nD (0.5×10^{-6} mD or 0.5×10^{-21} m^2). The thermodynamic model has been set up with this permeability for the unfaulted granite.

5. THERMODYNAMIC MODELLING

This section outlines the use of thermodynamic reservoir simulation of the Habanero field, the procedures for calibrating the model and what production results may be reasonably expected. The simulator used is AUTOUGH2, the University of Auckland version of TOUGH2 (Transport of Unsaturated Groundwater and Heat, version 2). AUTOUGH2 is usually used in conjunction with a file containing the geometric description of the model grid which together with the results is viewed with the graphical interface named MULgraph. The MULgraph geometry file format assumes a layered grid structure in the vertical direction, but allows arbitrary, unstructured polygonal columns in the horizontal plane.

5.1 Model Development

5.1.1 Conceptual Model

Development of the conceptual model began with a review of the natural state temperature profile as recorded in H01. The temperature profile (**Figure 5-1**) can be broken into 9 segments which represent layers of constant temperature gradient. The layers are labelled from top to bottom as Layers 1 to 9 and the thickness of the layers varies to follow the temperature profile.

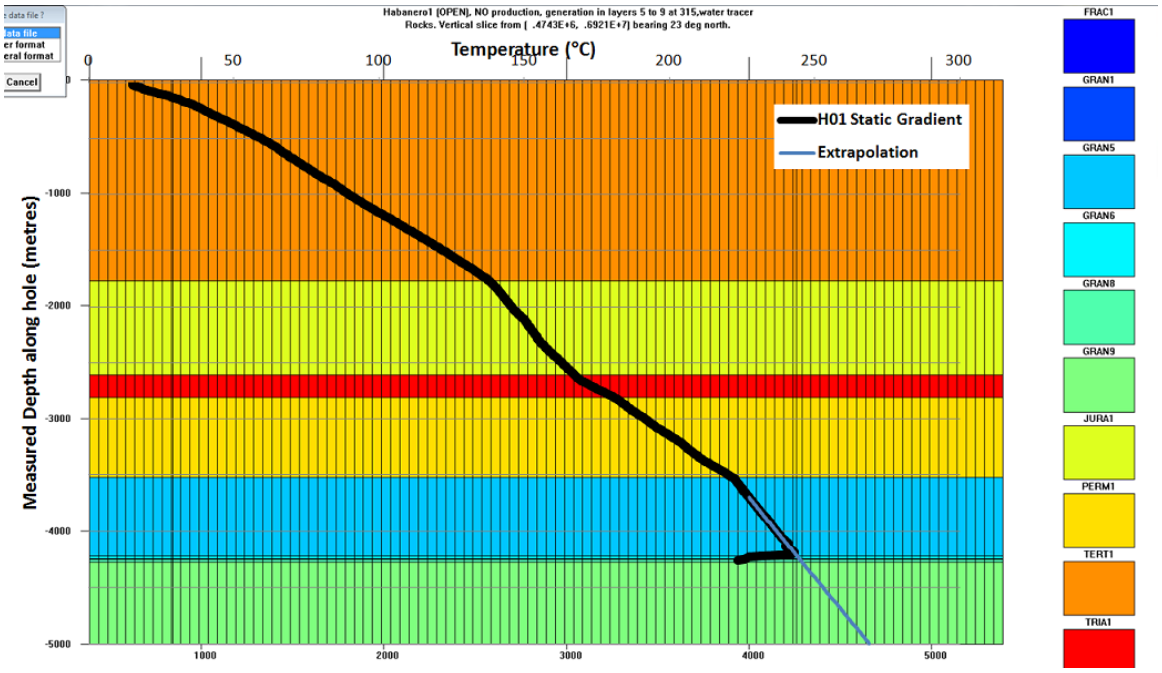


Figure 5-1: Cross section of the AUTOUGH2 model and H01 temperature profile.

The granite section is modelled with five layers: two thick layers (5 and 9) representing the bulk of the unfractured granite; two 25.6 m thick unfractured layers (6 and 8) above and below the reservoir to give good resolution of the stimulated area; and the 5 m thick reservoir layer itself, Layer 7.

The dimensions of the grid used for the model are 4x5x5 km in the x, y and z directions, respectively. Each layer has 50 x 50 m cells, i.e. 8,000 cells per layer for a total of 72,000 cells. The x-axis has been set-up approximately east-west and the y-axis approximately north-south. However, because the eastern boundary fault at the edge of the seismic cloud appears to be a permeability barrier, the grid has been established with the y-axis running parallel to the strike of this fault (**Figure 5-2**).

Layer 7 represents the Habanero Fault as a five meter thick, planar structure (**Figure 5-2**). The extent of the seismic cloud was used to define the area of the Habanero Fault with stimulated

permeability. A damaged zone, the "mud ring", has been modelled around H01 as evidenced by the limited seismicity during stimulation of H04 and the low injectivity of H01. These permeability variations have been incorporated into Layer 7 by assigning three "rock types" labelled "frac1" for the stimulated area, "gran1" for the unstimulated area and "mudd1" for the damaged area. The boundary fault (faul1), which has very low permeability, crosscuts the model from layers 5 to 9.

Because the model only extends over 20 km^2 (4 x 5 km) whilst the Innamincka Granite extends over ~1,000 km^2, the edge cells of Layer 7 have been increased in size from the standard 12,500 m^3 (50 x 50 x 5 m) to 12,500,000 m^3. These large cells simulate the extension of the Habanero Fault beyond the limited dimensions of the basic model.

The top of the model (Layer 1) is modelled as planar and so does not follow the topography of the Habanero area. However, since there are no surface outflows of geothermal brine and there is no hydraulic connection between the over pressured reservoir and the normally pressured shallow sediments, the topography of the surface is hydraulically irrelevant.

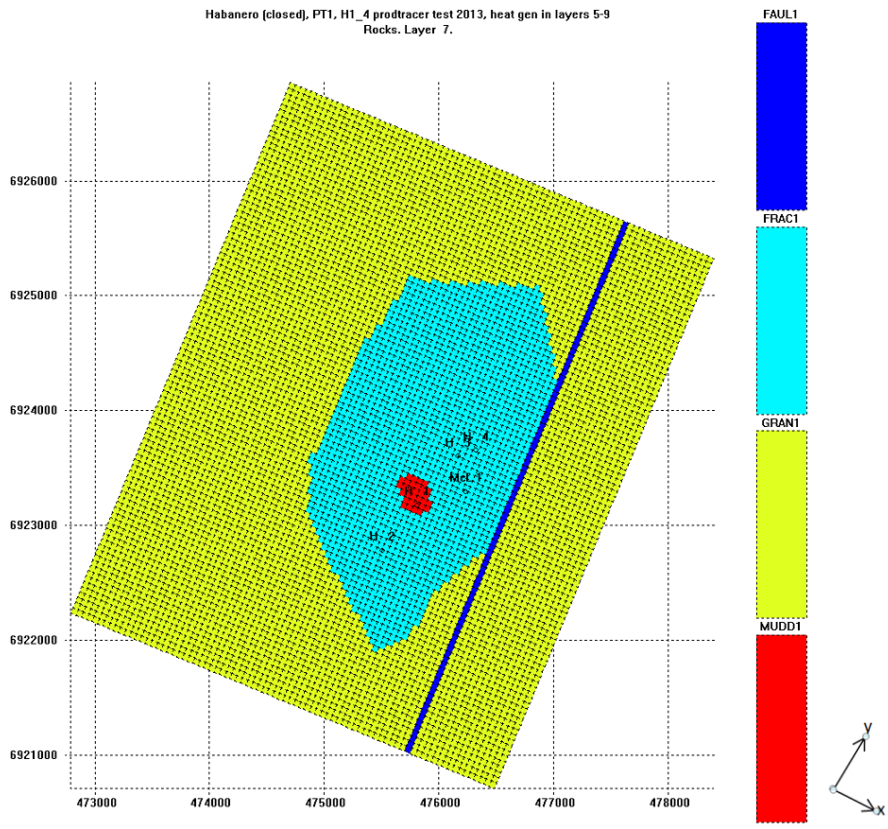


Figure 5-2: Plan view layer 7 depicting the fractured or stimulated area (cyan), mud ring or damaged zone (red), eastern boundary fault (blue) and unstimulated granite (yellow).

All earlier modelling done for Habanero has assumed horizontal features but gravity is potentially playing an important role on the inclined Habanero Fault. Hence, the full 3D model with horizontal layers has been tilted 10° to the west-south-west to allow for the effect of gravity on fluid flow.

In terms of boundary conditions, since the fluids within the granite are over pressured, the model has been set up with all side boundaries closed, meaning that there is no heat or mass transfer from the sides of the model. Similarly, because there are no surface outflows of geothermal brine and there is no vertical fluid flow from the granite, heat and mass transfer at the top of the model is ignored. At the bottom boundary, a constant heat influx was applied and in-situ heat generation was assumed in all the granite blocks.

5.1.2 1D Model Natural State Model

The objective of natural state modelling is to produce a simulation of the temperatures and pressures that were established over geological time and were present before any geothermal development occurred. This step in the process was used to calibrate thermal conductivity, heat flux and heat generation and involved running the simulation for hundreds of millions of years until approximately steady conditions were obtained.

A 1D version of the full 3D model was used for this step of the process. The same 4x5x5 km volume was used but with only one cell per layer. The model was layered as follows: 50 m thickness layers above 4,100 m and from 4,500 to 5,000 m. The 400 m in between, which contains the area of interest, was represented by 18 layers. This means a total of 111 layers (**Figure 5-3**). The model was constructed with 125 mW/m^2 heat flux at the bottom and 10 μW/m^3 heat generation in all the granite blocks.

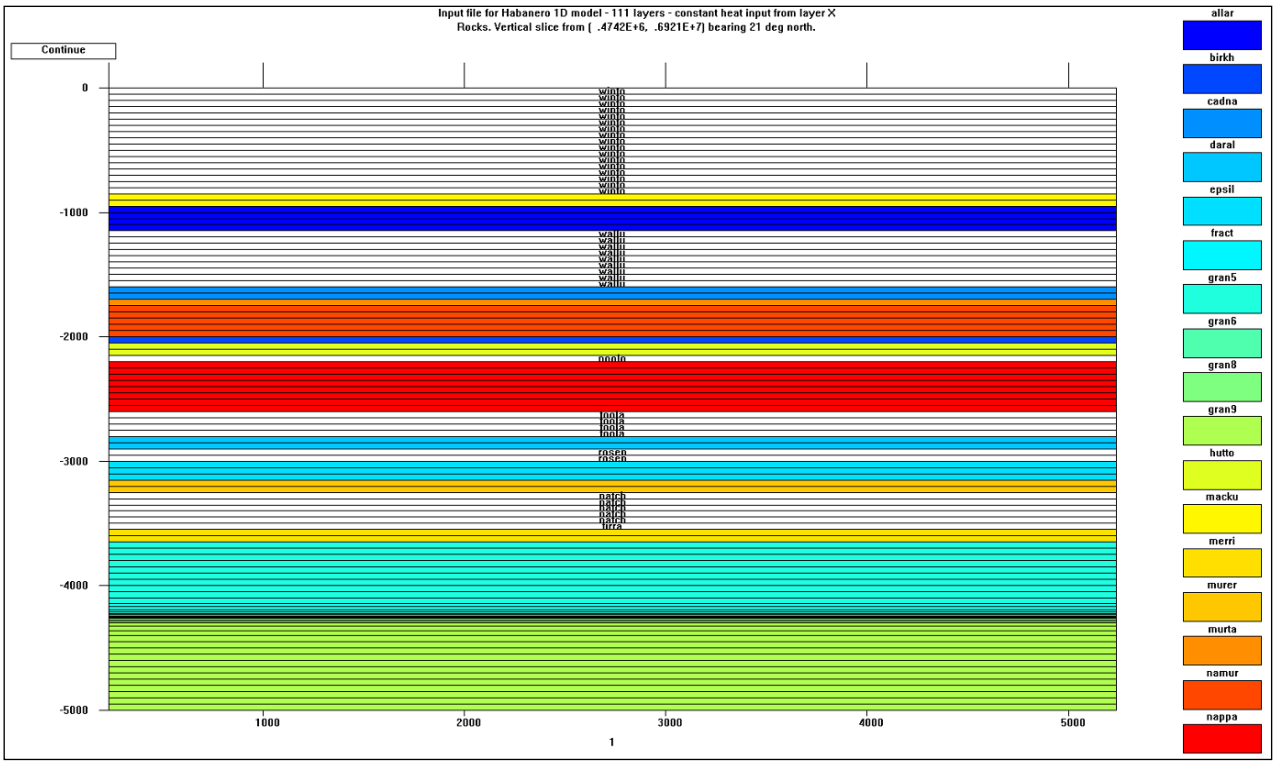


Figure 5-3. Cross section of the 1D model layer structure.

Rock properties from literature data and from previous studies carried out in the Cooper and Eromanga Basins (Gravestock et al, 1986, and Alexander and Boult, 1998) were used as a starting point. However, the rocks properties were grouped into the same 9 layers as had been defined for the full 3D model in preparation for inputting this information into the 3D model.

The calibration was developed from bottom up, i.e. matching layer by layer. A steep or flat temperature gradient indicates high or low thermal conductivity, respectively. The temperature distribution was continually compared against measured data from H01 until steady state was achieved. The thermal conductivity of the layers was adjusted until a good match in the temperature profile was found, as presented in **Figure 5-4**. The values of thermal conductivity for each rock type as summarised in **Table 5-1**.

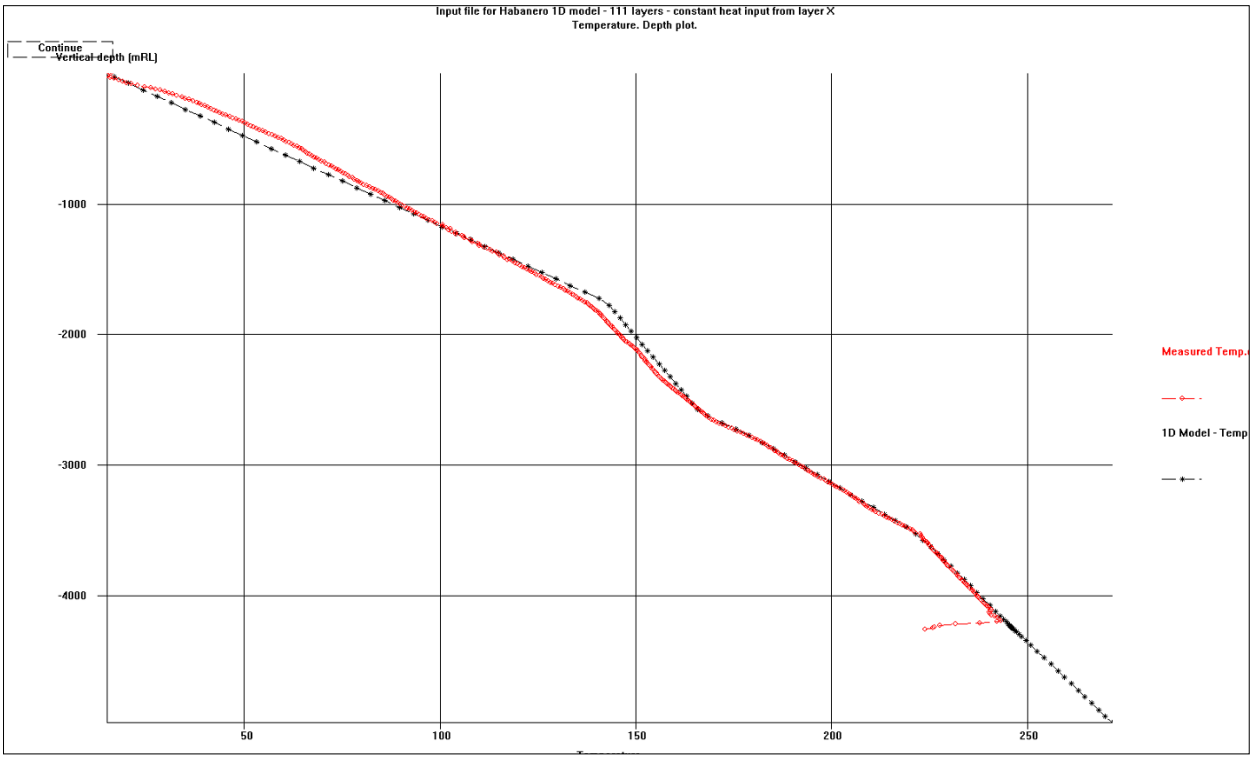


Figure 5-4: Temperature profile for the 1D model against measured temperature (m vs. °C).

Table 5-1: Thermal conductivity values obtained after the 1D model.

Layer	Conductivity W/(m.K)
1	1.9500
2	4.9900
3	2.0000
4	2.5000
5	3.7775
6	3.3950
7	3.3950
8	3.3950
9	3.3950

5.1.3 3D Natural State Model

This step in the process simulates the development of the full geothermal system over geological time. As for the 1D model, it involves running the simulation for millions of years until approximately steady conditions are obtained. The simulation time for the Habanero 3D natural state model was 10 million years.

Having established appropriate values for the thermal conductivities, heat influx and in-situ heat generation, these same values were transferred into the 9 layer, fully 3D model. Additionally, temperature and pressure were assigned to each cell in the initial conditions or 'incon' file, acknowledging the tilting of the model and the temperature and pressure profiles observed in H01.

A simulation was set to run for 10 million years and the temperature profile generated by this natural state simulation is shown in **Figure 5-5** along with the temperature data recorded in H01. The thermodynamic conditions obtained from this simulation have been used as the official Habanero AUTOUGH2 'incon' file for subsequent runs.

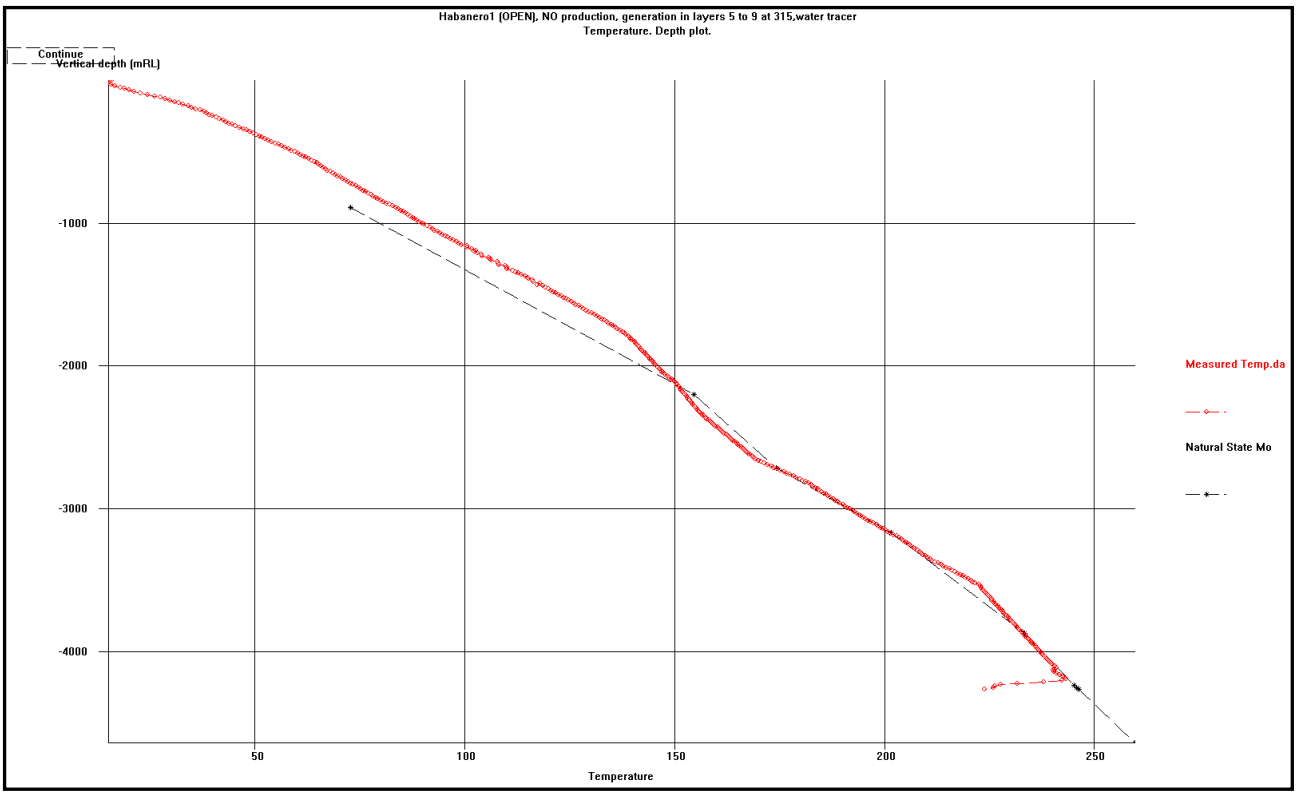


Figure 5-5: Temperature profile for the 3D natural state model against measured temperature (m vs. °C).

5.2 Model Calibration

5.2.1 Permeability Calibration

The permeability of the stimulated and damaged zones was calibrated using stable closed-loop production and injection data corresponding to the period from 16th to 21st August, 2013.

Measured surface production and injection pressures were first corrected to bottom hole conditions, allowing for frictional and gravitational pressure changes along each well.

In order to match the bottom hole pressure at H04, estimated as 72.50 MPa, the permeability of the stimulated fracture (frac1) was adjusted until a good match was found. The best match was obtained using a value of 800 mD in x and y directions or 4,000 mD.m for the transmissibility of the stimulated fracture. This transmissibility value is in line with the estimates derived from pressure transient tests (**Section 4.1.6**).

For the damaged zone around H01, the target value of injection pressure to match was 83.41 MPa and the best fitting permeability value for the damaged zone was 28 mD, giving transmissibility of 140 mD.m, again in line with pressure transient analysis results.

5.2.2 Porosity Calibration

The porosity of the stimulated and damaged zones was calibrated by using the two tracer tests carried out so far in Habanero.

Between 18th December, 2008 and 22nd February, 2009 a closed-loop circulation test was conducted between the injection well H01 and production well H03. As part of the circulation test, two tracers were injected into H01: 100 kg of the tracer 1,3,5-naphthalene trisulphonate (1,3,5-nts); and 50 kg of the tracer uranine (sodium salt of fluorescein). The purpose of the tracer test was to characterise the connection between these two wells. Over the following 66.5 days, approximately 50,000 tonnes of brine were circulated between the wells at approximately 14 kg/s.

This circulation and tracer test was simulated with AUTOUGH2 and the results were matched to the 1,3,5-nts sample data as analysed by University of Utah (**Figure 5-6**). The porosity values obtained for the stimulated fracture and mud ring from simulating the H01_H03 tracer test were 0.5% and 0.36% respectively.

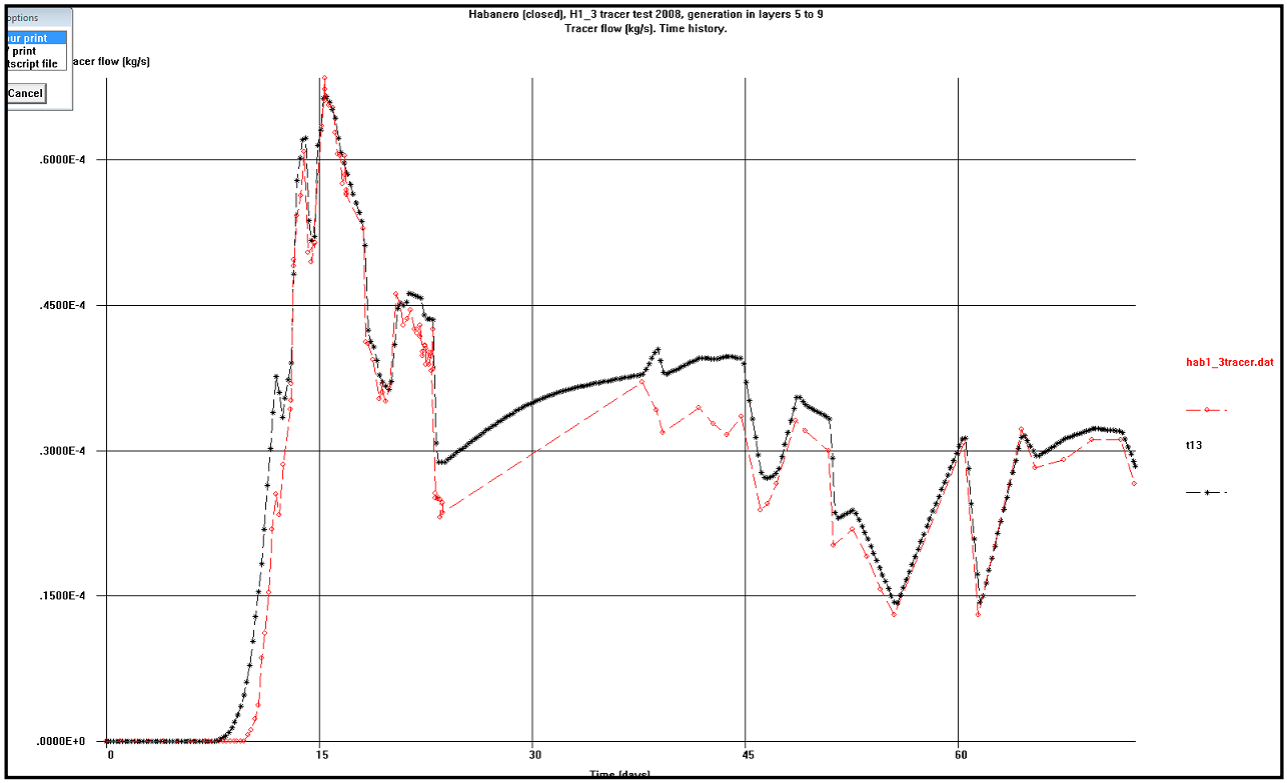


Figure 5-6: Tracer flow profile for H03 (kg/s vs. days)-modelled (black) using homogeneous x and y permeability for the reservoir, against field data (in red).

Similarly, the most recent H01_H04 tracer test was simulated over the period 4th June to 6th September, 2013. The tracer used was 2,6-naphthalene disulphonate and the tracer match obtained is shown in **Figure 5-7**. The porosity values obtained from matching this tracer test were 1.4% for the stimulated fracture and 0.36% for the damaged area.

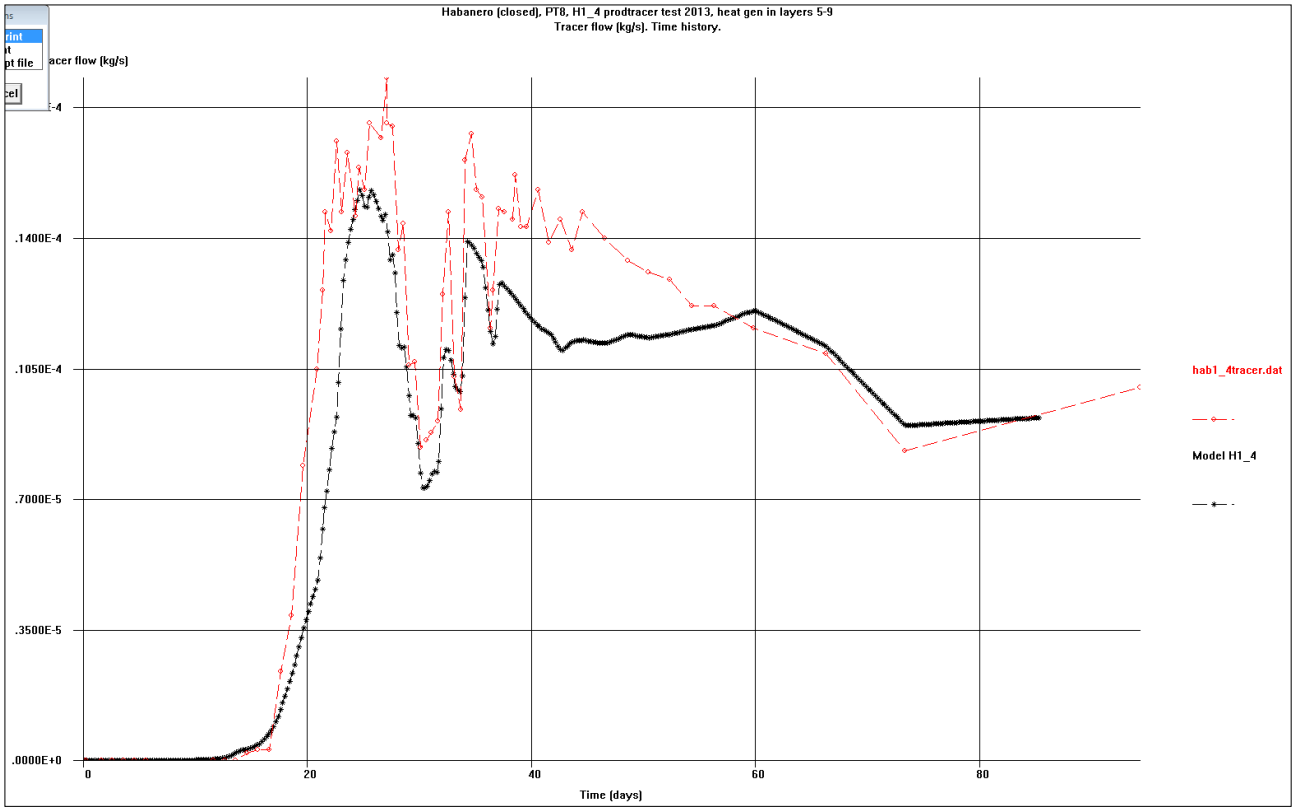


Figure 5-7: Tracer flow profile for H04 (kg/s vs. days)-modelled (black) using isotropic x and y permeability for the reservoir, against field data (in red).

5.2.3 Permeability Anisotropy

In considering the overall shape of the seismic cloud (**Figure 5-2**), it is apparent that there is a distinct elongation of the seismic cloud along the north-south or y-axis. In view of this elongation, it is considered most likely that there is anisotropy in the permeability of the stimulated area. Various laboratory studies of shearing of fractures have demonstrated that permeability perpendicular to the direction of shearing can be between 2 and 10 times the permeability parallel to the direction of shearing.

To investigate the impact of this potential anisotropy at Habanero, injection of a tracer was modelled with various levels of anisotropy. As the level of permeability anisotropy increases, the elongation of the tracer spread becomes more pronounced. **Figure 5-8** shows the spread of the tracer with 2:1 ratio between y permeability and x permeability for Layer 7. This spread of the tracer seems to match reasonably well with the shape of the seismic cloud, so 2:1 permeability anisotropy (ky = 1,200 mD, kx = 600 mD) has been adopted for the base case reservoir model as well as forecast scenarios.

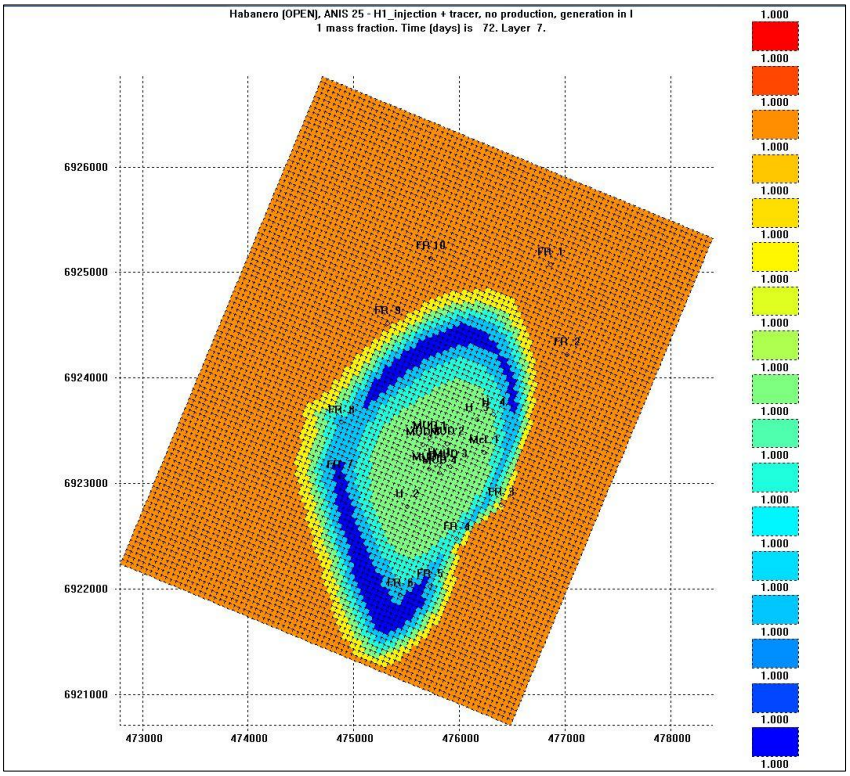


Figure 5-8: Spread of tracer in Layer 7 with 2:1 permeability anisotropy

To validate that this permeability anisotropy was reasonable, the H04-H01 tracer match was re-run. The best fitting model retained porosity of 1.4% in the stimulated fracture but required permeability for the damaged zone of 58 mD in the y and 29 mD in the x direction. The match remains reasonable as is shown in **Figure 5-9**.

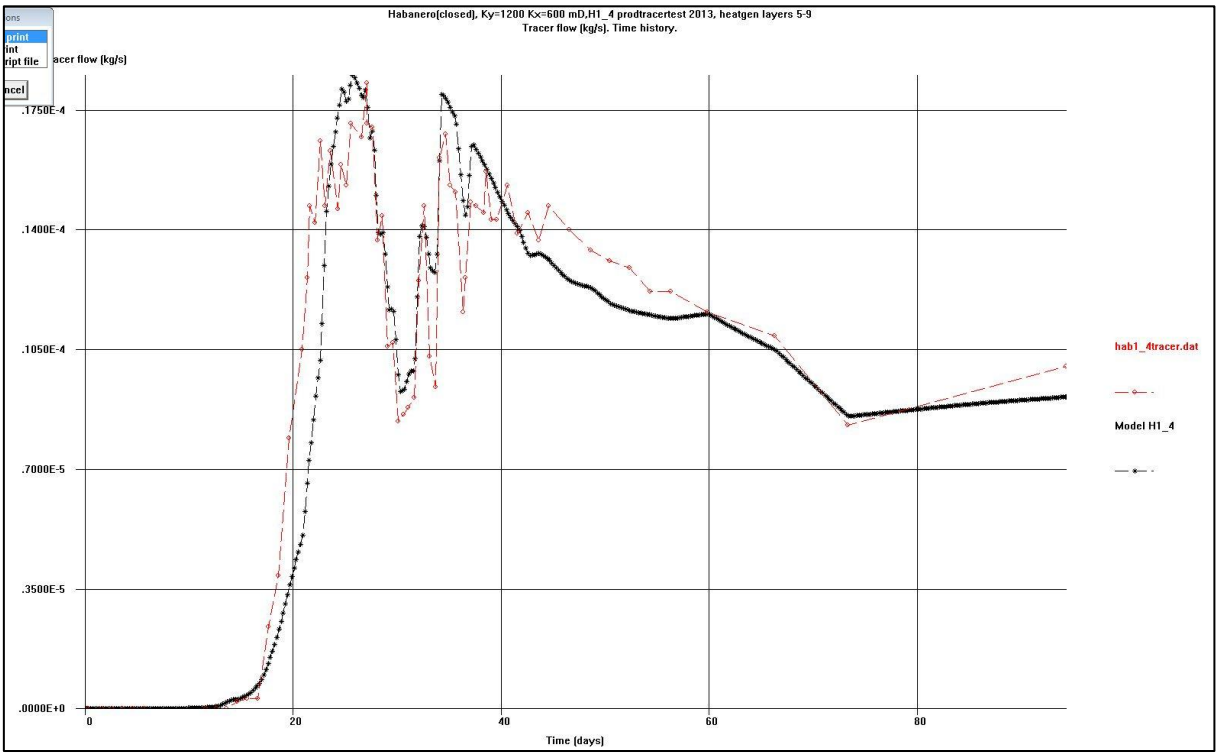


Figure 5-9: Tracer flow profile for H04 (kg/s vs. days) - modelled (black) using anisotropic x and y permeability for the reservoir, against field data (in red).

5.2.4 Calibrated Granite Properties

In summary, after the calibration process, the rock properties for the Habanero simulation model are shown in **Table 5-2** below.

Table 5-2: Rock properties used for the Habanero reservoir AUTOUGH2 model.

Layer	Grain Density kg/m^3	Porosity %	Permeability x mD	Permeability y mD	Permeability z (Vert) mD	Thermal Conductivity W/(m.K)	Specific Heat J/(kg.K)
5	2,700	0.3	1 x 10^{-7}	1 x 10^{-7}	1 x 10^{-7}	3.7775	960
6	2,700	0.3	1 x 10^{-7}	1 x 10^{-7}	1 x 10^{-7}	3.3950	960
Stimulated Fault	2,600	1.4	600	1,200	40	3.3950	960
Mud ring or Damaged area	2,600	0.36	29	58	10	2.5000	900
Non-Stimulated Fault	2,700	0.3	10	10	10	3.3950	960
8	2,700	0.3	1 x 10^{-7}	1 x 10^{-7}	1 x 10^{-7}	3.3950	960
9	2,700	0.3	1 x 10^{-7}	1 x 10^{-7}	1 x 10^{-7}	3.3950	960
Boundary Fault	2,500	5.0	1 x 10^{-7}	1 x 10^{-7}	1 x 10^{-7}	2.5000	900

5.3 Forecast Scenarios

In preparing forecasts of production rate and temperature, three different well layouts have been considered: staggered line drive; square grid or 5-spot; and triangular grid or inverted 4-spot. The idealised well layouts for these three patterns are shown in **Figure 5-10**.

In applying these idealised patterns to the reservoir, Habanero 4 has been assumed in all cases to be an injector and other well locations were constrained to being within the seismic cloud so that penetrating the Habanero fault could be assured. These constraints inevitably lead to some skewing of the idealised patterns.

Initially, well layouts with ~800 m well spacing were investigated, but it was immediately clear that this well spacing cooled off too quickly. Each of the patterns was then stretched to about the maximum available within the seismic cloud, which was a spacing of ~1,100 m.

For each scenario, closed-loop circulation at 25, 35 and 45 kg/s per well were modelled for a period of 20 years, assuming a bottom hole re-injection temperature of 95°C. The temperature profile for each of these simulations is presented in **Figure 5-11** to **Figure 5-13**. In the temperature profile plots the colour coding depicts the coolest areas in blue (70°C) and the hottest in red (240°C).

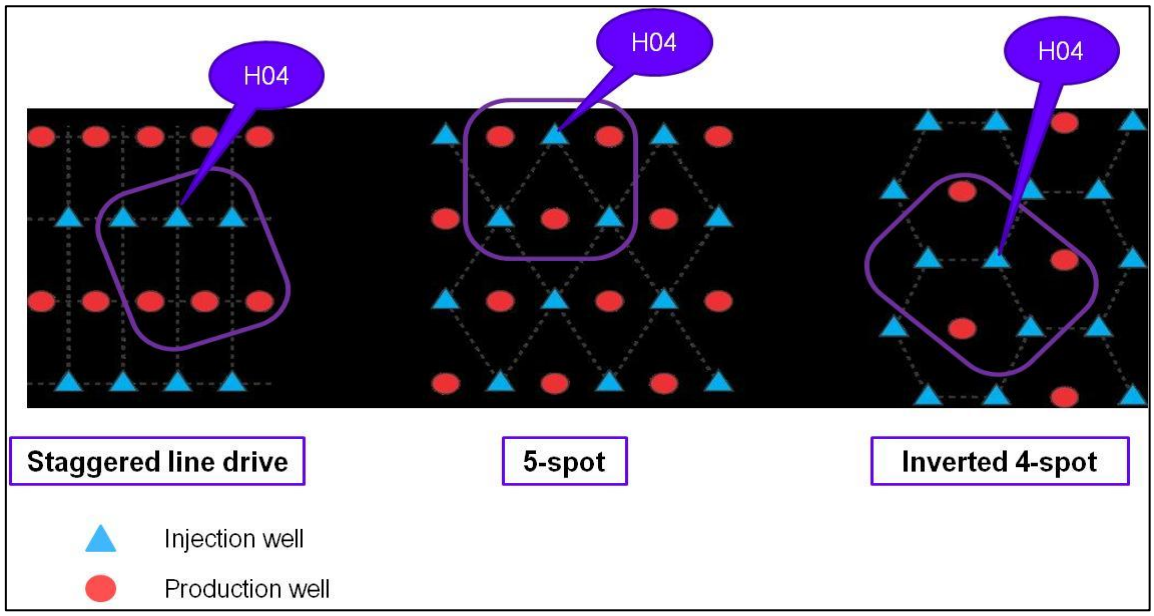


Figure 5-10: Idealised well layouts

5.3.1 Staggered Line Drive

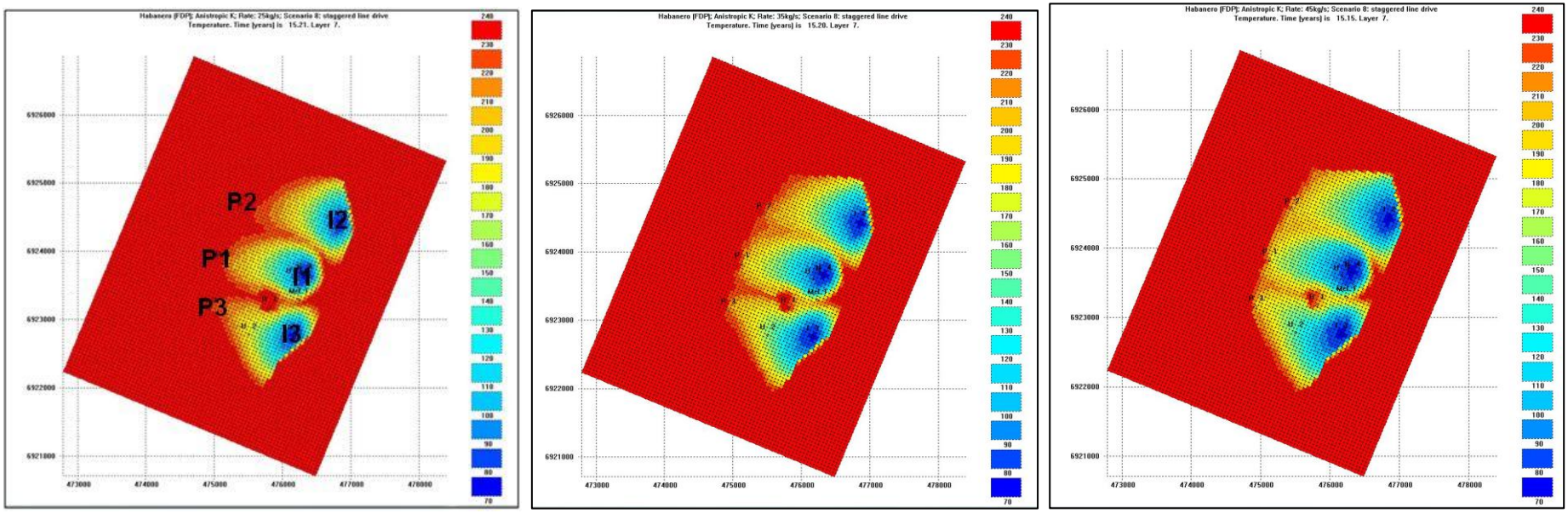


Figure 5-11: Staggered Line Drive case temperature profiles (in °C) after 15 years. From left to right cases at: 25 kg/s, 35 kg/s, 45 kg/s.

For the staggered line drive scenario, gravity accelerates the movement of cooler brine from the updip injectors to the downdip producers. In addition, the constraints imposed by the area of the seismic cloud result in the distance between injector 1 (I1) and producer 1 (P1) being shorter. This shorter distance and the influence of gravity cause P1 to cool down quicker than the other two producers. This effect is less pronounced at higher rates where gravity plays less of a role. Producer 2 remains the best production well for this arrangement.

5.3.2 Triangular grid or inverted 4-spot

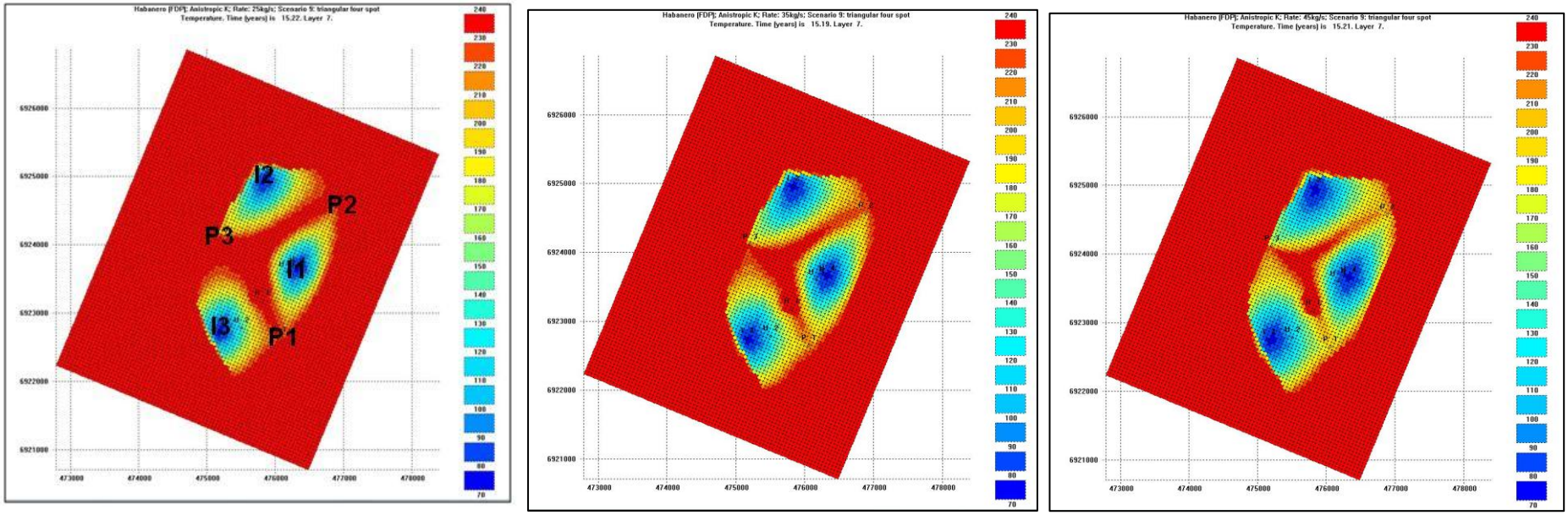


Figure 5-12: Triangular grid case temperature profiles (in °C) after 15 years. From left to right cases at: 25 kg/s, 35 kg/s, 45 kg/s.

In this scenario, although producers 1 and 3 (P1 and P3) are located in spots which are slightly hotter than producer 2 (P2), their production temperature falls off quicker due to the proximity to injector 1 (I1) and the influence of gravity. Additionally the permeability anisotropy and the damaged area around H01 diminish the swept area in comparison to the staggered line drive.

5.3.3 Rectangular grid or regular 5-spot

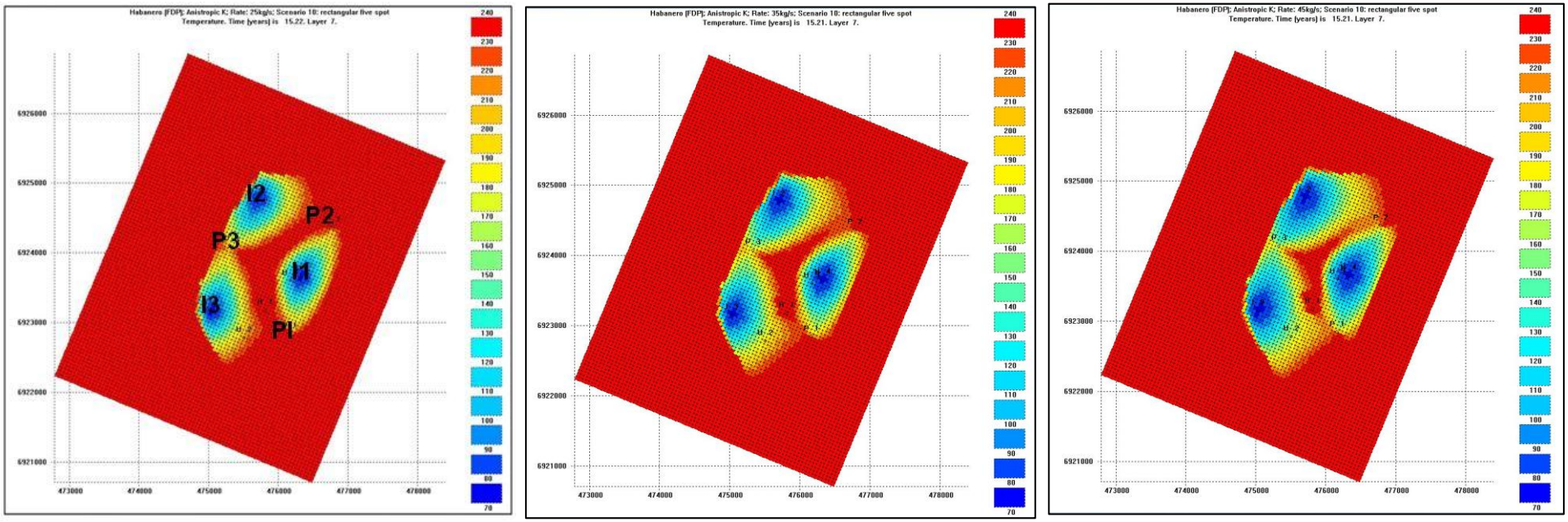


Figure 5-13: Rectangular grid case temperature profiles (in °C) after 15 years. From left to right cases at: 25 kg/s, 35 kg/s, 45 kg/s.

The temperature profiles corresponding to the 5-spot pattern show producers 1 and 2 (P1 and P2) are equally affected by injector 1 (I1) due to their alignment with the orientation of maximum permeability. Producer 3 (P3) cools down faster than in any other case as a result of having two injectors nearby.

5.4 Comparison of Layouts

A comparison of the average flowing bottom hole temperatures for each of the three well layouts at 35 kg/s is presented in **Figure 5-15**. Additionally, **Figure 5-11** to **Figure 5-13** provide a visual comparison of the sweep efficiency and the flowing (surface) production temperatures obtained for each of these three layouts after 15 years of production.

The average flowing bottom hole temperatures (**Figure 5-14**) indicate that the 5-spot pattern cools off earliest. This is because the pattern aligns producers and injectors along the orientation of the likely maximum permeability. The visual comparison of the layouts (**Figure 5-15**) also shows that the 5-spot layout delivers the most uneven production temperatures, with one well significantly cooler than the other two.

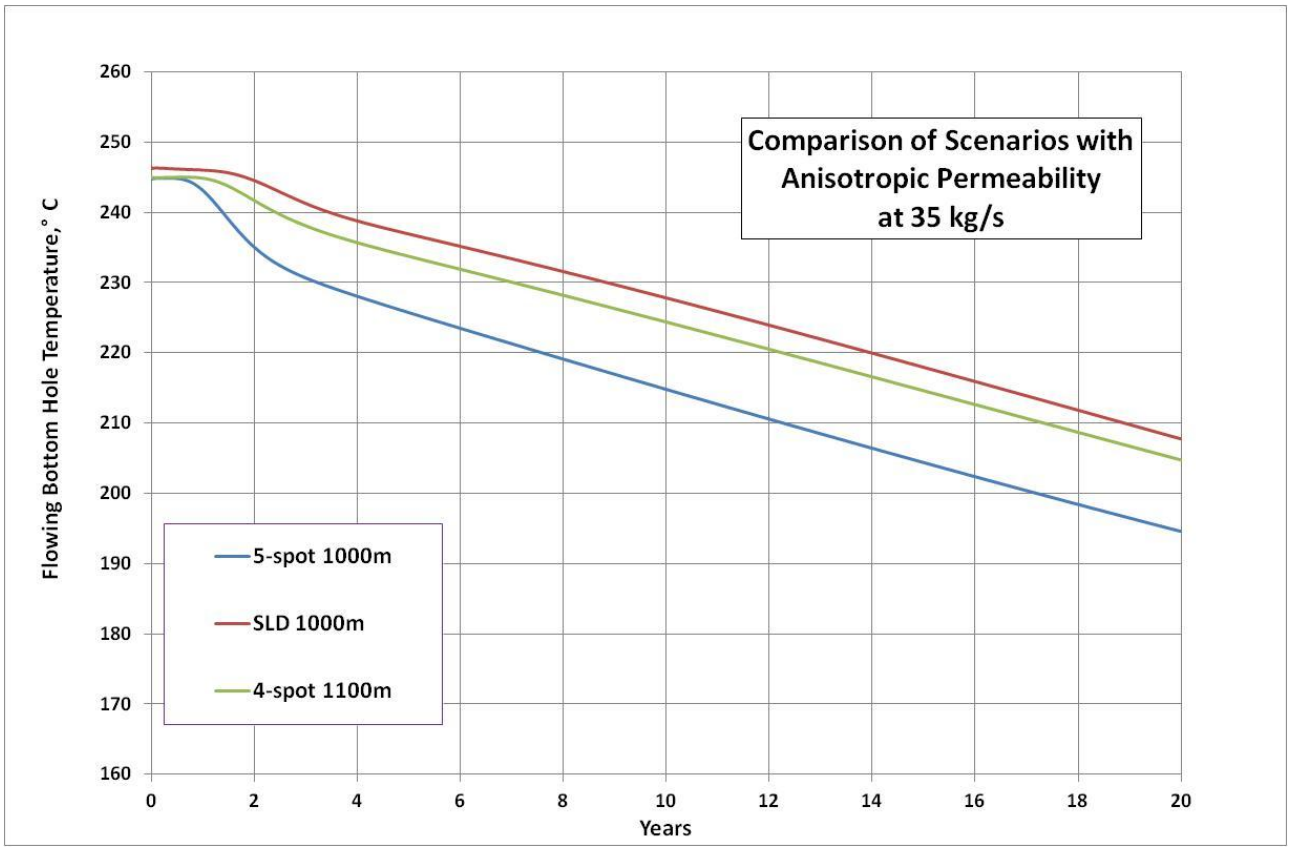


Figure 5-14: Comparison of average flowing bottom hole temperatures over time for three well layouts (°C vs. years).

The staggered line drive starts out with the highest average temperature because all the producers are down dip and maintains this advantage over 20 years. However, one of the producers in this layout (P1) cools off faster than the other two producers, most probably because the distance between injector 1 (Habanero 4) and P1 is shorter than in other layouts.

Of the three layouts, the most even temperature behaviour appears to occur when a 4-spot layout is used. On the other hand, the staggered line drive clearly shows the highest swept area.

For a larger-scale development plan, extending the layout plays an important role from both the engineering and cost perspective. Both the triangular and rectangular layouts are relatively easy to extend compared to the staggered line drive. For the staggered line drive, adding another row of injectors to the west implies the producers must have massive stimulations to extend the seismic cloud. This will cool these producers and result in lower average temperatures.

Considering the discussion presented above, a 1 to 3 ranking system for worst to best scenario has been used to evaluate the options and this is summarized in **Table 5-3**.

Table 5-3: Matrix of factors considered for evaluating best layout for development plan.

Factor	Layout		
	SLD	4-spot	5-spot
Sweep efficiency	3	1	1
Even temperatures	2	3	1
Average temperatures	3	2	1
Extensibility	1	3	3
Stimulation cooling	1	3	3
Total	**10**	**12**	**9**

From this analysis of the options, the triangular 4-spot layout is recommended to provide the best outcome, balancing short-term temperature against long-term extensibility. The locations of the proposed wells are summarized in **Table 5-4**.

Table 5-4: Recommended wells locations (triangular 4-spot)

Well Type and Name	GDA94 / Central (Meridian is 141°)	
	X	Y
Injector 1 - (H 4)	476,326.1	6,923,652.2
Injector 2 - (I 2)	475,832.9	6,924,957.5
Injector 3 - (I 3)	475,164.9	6,922,740.8
Producer 1 - (P 1)	476,060.0	6,922,643.6
Producer 2 - (P 2)	476,886.5	6,924,561.8
Producer 3 - (P 3)	475,204.9	6,924,112.0

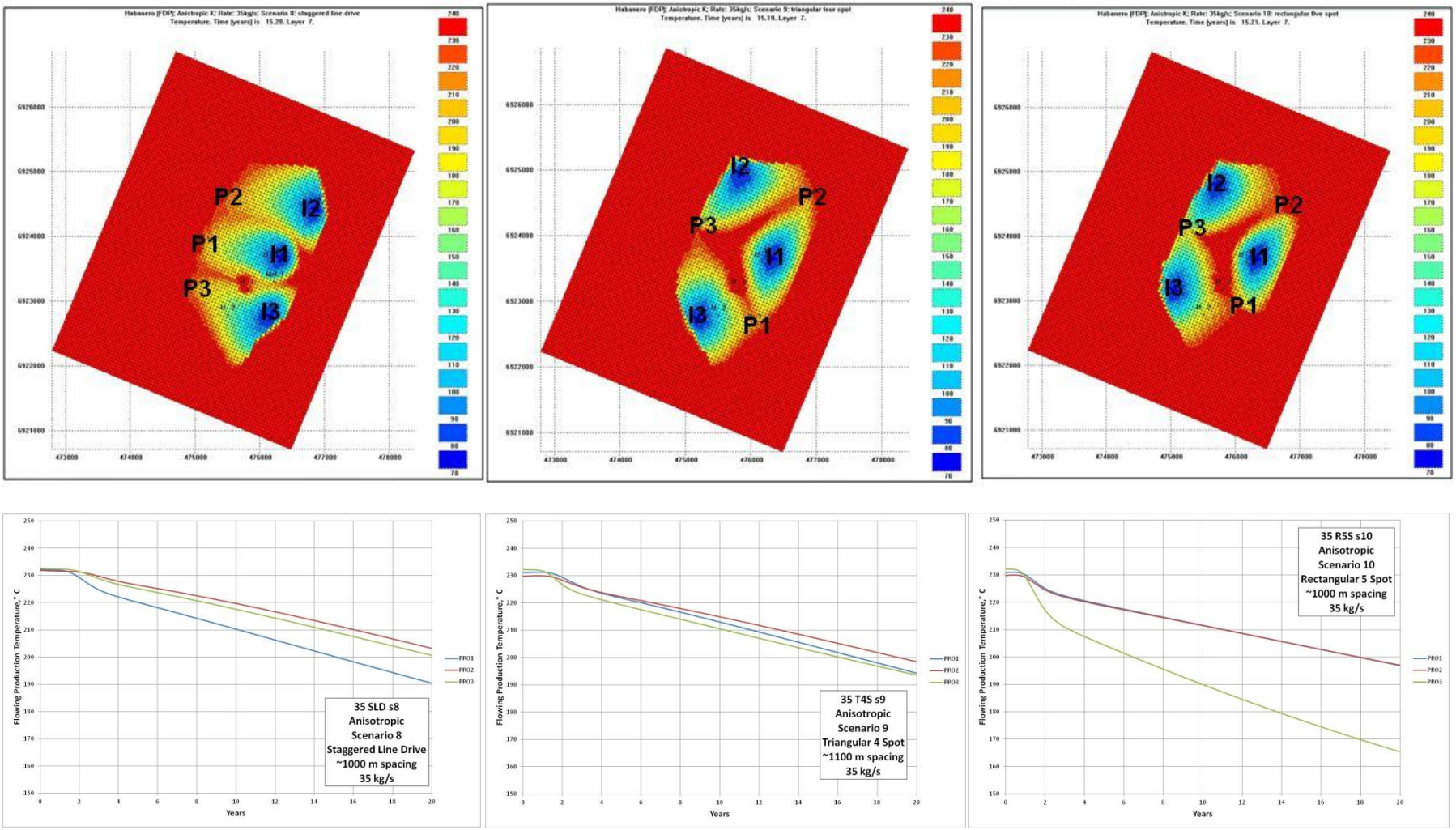


Figure 5-15: Comparison of sweep patterns (top) and production temperature profiles (bottom) for 35 kg/s per well. From left to right, Staggered Line Drive, Triangular 4-spot and Rectangular 5-spot.

5.5 Wellbore Modelling

5.5.1 Model Development and Calibration

A thermodynamic model of the wellbore has been developed in WellCAT, a wellbore flow simulation package. The model incorporates the wellbore tubulars, cement, fluids and surrounding rocks. Calibration of the model has been done using two different flow rates in H04: the 19 kg/s flow rates at the end of the H04-H01 closed-loop; and the 6 kg/s open flow rate from H04 after the end of closed-loop test; shows the output from the model at 6 kg/s flow with flowing bottom hole temperature of 236°C, as recorded with a production log in H04. The actual flowing temperature recorded at site was 193°C versus 192°C from the model.

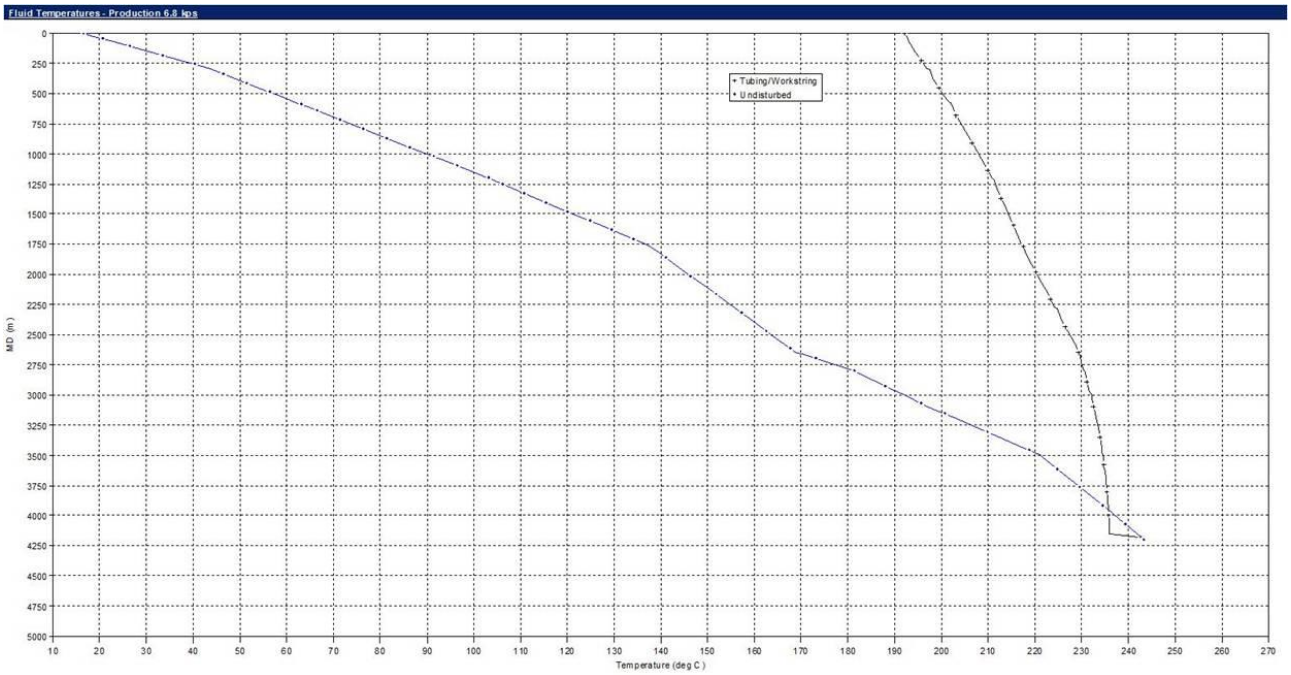


Figure 5-16: Wellbore model output for 6 kg/s flow showing 192°C production temperature

5.5.2 Forecast Production Temperatures

The calibrated WellCAT model was used to estimate surface production temperatures after three months of continuous flow for a range of flowing bottom hole temperatures and a range of flow rates. The results are shown in **Table 5-5** below. These estimates were used to correct the simulated flowing bottom hole temperatures to their equivalent surface production temperatures.

Table 5-5: Estimated surface production temperatures after three months continuous flow at three flow rates for various flowing bottom hole temperatures

Flowing Bottom Hole Temperature °C	Surface Production Temperature at 25 kg/s	Surface Production Temperature at 35 kg/s	Surface Production Temperature at 45 kg/s
250	232.4	235.6	237.4
240	223.7	226.7	228.4
230	215.1	217.8	219.3
220	206.5	208.9	210.3
210	197.9	200.0	201.2
200	189.4	191.2	192.2
190	180.9	182.4	183.2
180	172.5	173.5	174.2

The resulting surface production temperatures for the recommended triangular 4-spot well layout at 35 kg/s per well is shown in **Figure 5-17**.

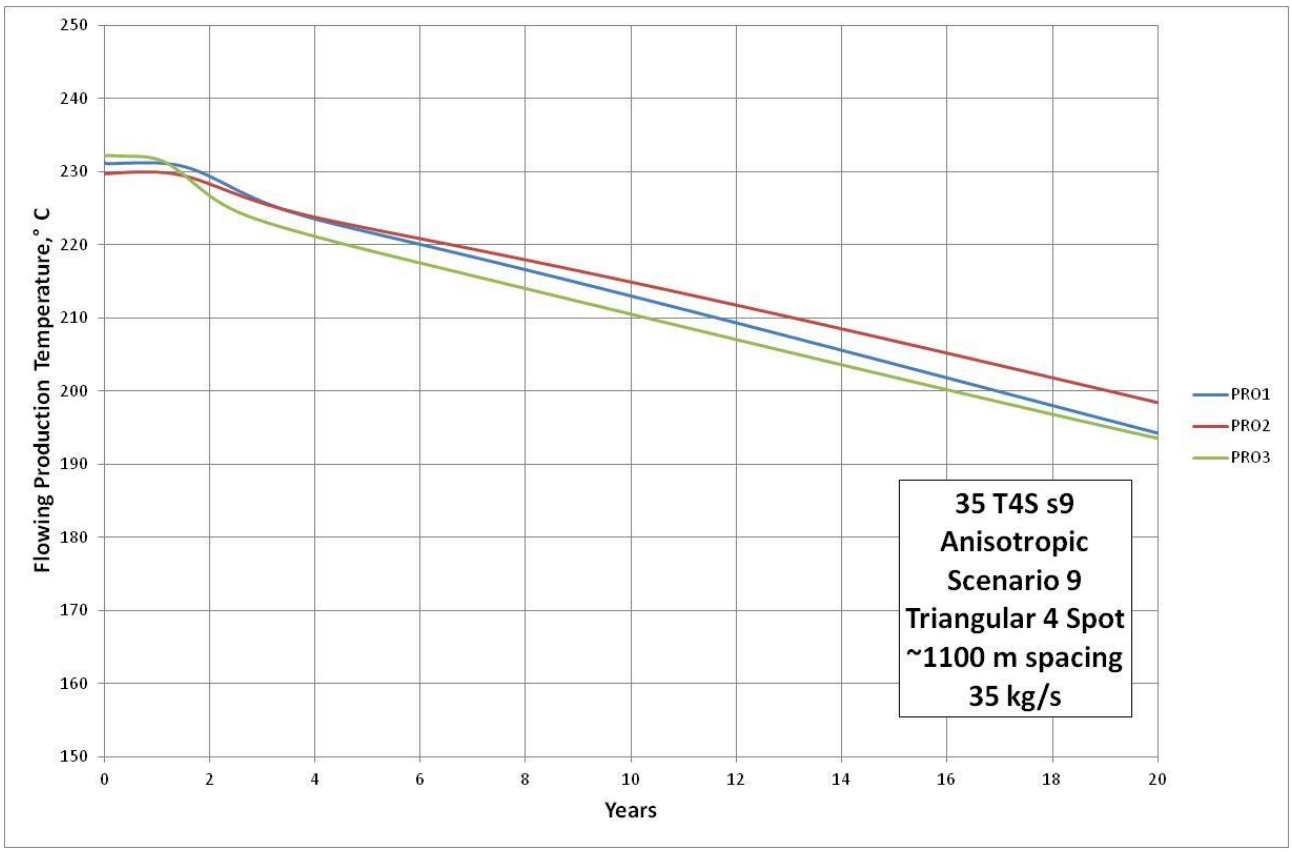


Figure 5-17: Surface production temperatures of the triangular 4-spot layout at 35 kg/s

5.6 Geothermal Resources

The geothermal resources developed by the various scenarios outline in this FDP have been estimated based upon the simulation-derived surface production temperatures shown in **Figure 5-17**. Three well scenarios have been considered: 2 wells; 4 wells; and 6 wells. The results are summarised in **Table 5-6** below and compared to the Measured Geothermal Resource estimate.

Table 5-6: Geothermal Resource Estimates for 2, 4 and 6 Well Developments at Habanero

Parameter	Units	Seismic Cloud Only	Seismic Cloud Only	Seismic Cloud Only	Measured Geothermal Area
Area	km^2	4	4	4	16
Depth range	m	4,000 – 4,500	4,000 – 4,500	4,000 – 4,500	3,700 – 4,800
Thickness	m	500	500	500	1,100
Volume	km^3	2	2	2	17.6
Average temperature	°C	243	243	243	247
Cut-off temperature	°C	180	180	180	180
Heat Capacity	$MJ/(m^3.K)$	2.6	2.6	2.6	2.6
Heat in Place	PJ_{th}	330	330	330	3,100
Life of Project	years	15	15	15	20
No of Wells	#	2	4	6	14
Recoverable Thermal Energy	PJ_{th}	10	20	30	80

Note that the geothermal resources as developed by the small scale development scenarios outlined in the FDP are all significantly smaller than the Measured Geothermal Resource. This is because: the FDP scenarios are focussed on the smaller area of the existing seismic cloud; have fewer wells; and operate for only 15 instead of 20 years.

6. RESERVOIR MANAGEMENT

6.1 Reservoir Management Objectives

The reservoir management objective is to maximise the thermal power delivered to the brine heat exchangers over the life of the field. This will likely require adjustment of well flows to lessen the impact of early cooling of individual production wells.

6.2 Field Layout

The wells will be connected to two headers. The production wells will be connected to a common, production header operating at 30-32 MPa. The injection wells will be connected to a common injection header, operating at ~10 MPa above the production header pressure (i.e. 40-42 MPa). Actual operating pressures for these two headers will be governed by the combined productivity and combined injectivity of the wells.

6.3 Stimulation Strategy

The Habanero reservoir has been developed by stimulation of an existing fault structure and the extent of the seismic cloud indicates the minimum extent of that fault. In preparing a stimulation strategy for future wells the following issues need to be kept in mind:

- The seismic cloud is believed to represent the area where development wells can be drilled with confidence that they will encounter the fault system.
- In order to allow for future development drilling beyond the existing seismic cloud, some development wells will need large volume stimulation which will extend the cloud even further.
- The extended stimulation of H04 resulted in significant cooling of the reservoir around the well. A temperature log before stimulation recorded flowing temperature of 241°C but a second temperature log at the end of the H04-H01 closed loop recorded only 236°C. This data suggests that future production wells should not be subjected to large volume stimulations.
- The successful results of two local stimulations at H03 and H04 show that all wells should be stimulated to improve the connection between the new wellbore and the fault system.

Consequently, the recommended stimulation strategy is as follows:

- Production wells - local stimulation with ~2.5 ML of water
- Injection wells - extended stimulation with ~30 ML of water.

An analysis of stimulation pressures used at Habanero (Holl, 2013b) has shown that relatively low stimulation pressures can be used because the Habanero Fault is critically stressed. A maximum stimulation pressure of 48.3 MPa (7,000 psi) is recommended.

The water used for stimulation could potentially be sourced from the current Habanero reservoir, by producing into existing surface dams and then later re-injected the brine under pressure.

6.4 Well Testing Strategy

The testing strategy should be different for production and injection wells. Production wells should be flow tested and stimulated once the well has been completed. The sequence should commence with a pre-stimulation flow test, and then the stimulation, followed by a post-stimulation flow test. Injection wells should only be stimulated, without any flow tests.

Each production flow test will commence with well-warming, flowing the well at 2 L/s for 12 hours. Then the flow rates will be increased monotonically to the maximum rate achievable whilst keeping flowing well head pressure above 22.6 MPa (3,300 psi). This pressure limit is set so as to avoid excessive breakout within the granite.

Based upon the performance of H04 before and after local stimulation, the recommended rate steps for the pre-stimulation test are: 2, 5, 10, 15 and 20 kg/s. The flow rate will be controlled using a variable choke with minimal adjustment during each flow period. Actual choke settings will be selected on site based upon the clean-up flow rates and the well performance on the previous period.

6.5 Tracer Testing

Once all wells are completed and the field has been operating for some time, say 6 months or more, multi-well tracer testing should be conducted. This should involve injection of different naphthalene sulphonate tracers, one into each of the injectors, and capture of production samples from each of the producers. The results from such a test will provide information that should assist with long-term management of production temperatures.

6.6 Performance Monitoring

Each well will be equipped with temperature and pressure sensors and an orifice plate flow meter, with the data transmitted back to the DCS in the control room.

The production wells will also be equipped with a control valve to allow for future adjustment of well rates in order to lessen the impact of early cooling of individual wells. However, adjustment of flow rates with these control valves will reduce overall rates and so should be avoided unless absolutely necessary.

7. GEOTHERMAL WELLS

7.1 EGS Drilling

Drilling EGS wells in the Cooper Basin is an unusual challenge. As seen in **Figure 7-1**, the wells fit in-between traditional geothermal wells and the most extreme of the current HPHT wells. It is the combination of high temperatures AND high overpressures that makes these wells unique. In geothermal and steam reinjection wells the temperatures are sometimes higher; however in these cases the pressure is normally low. In HPHT wells the pressure is often higher at total depth; however the temperature is normally lower and the high pressures originate from the significant depth of the wells rather than from an over pressured zone such as is present at Habanero.

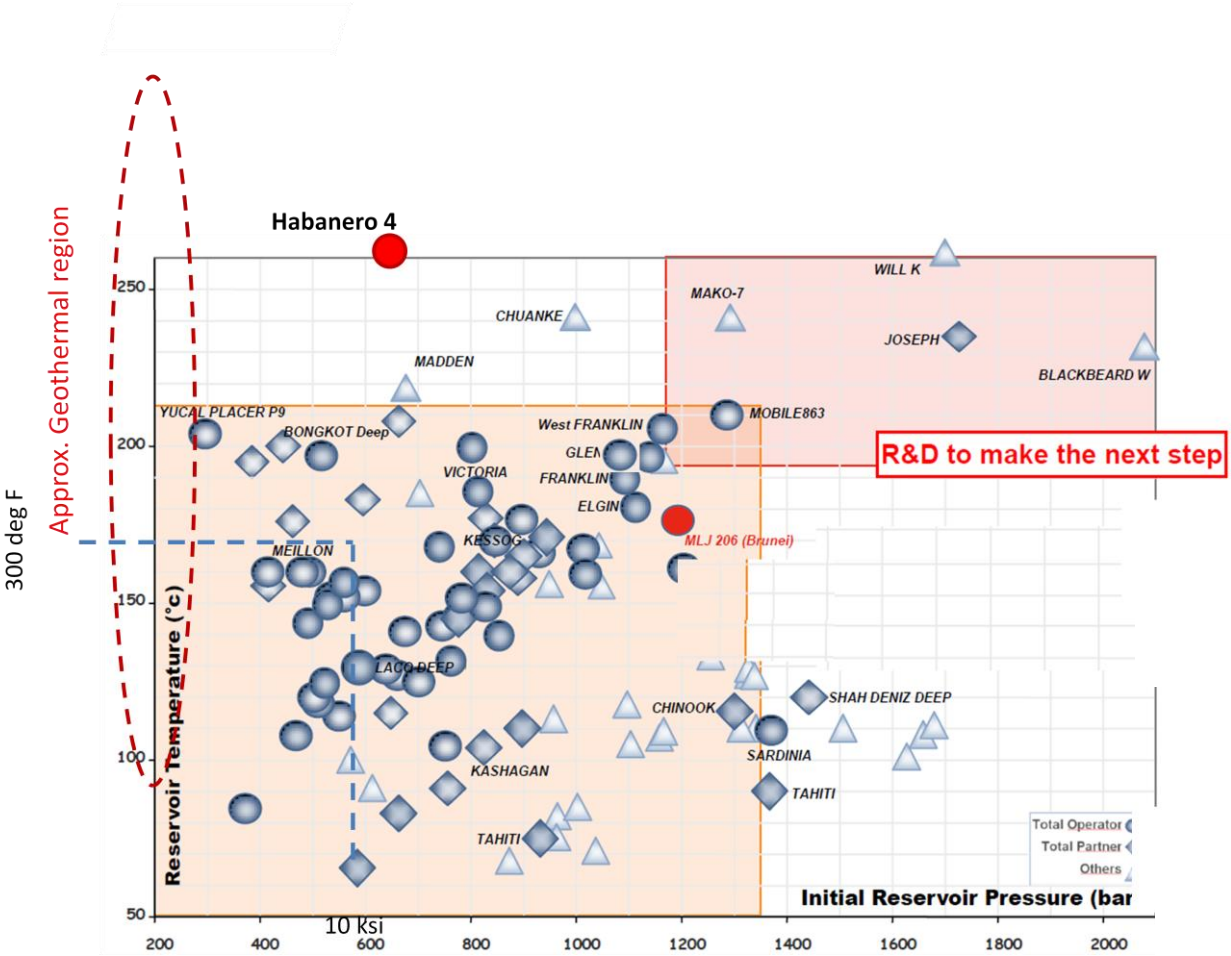


Figure 7-1: Comparison of EGS to Geothermal and HPHT Wells

Other aspects of EGS wells that increase the complexity include:

- An over pressured zone is created by the Roseneath Shale (regional seal) that results in pressures of 5,000 psi above hydrostatic pressures
  - Below the Roseneath shale, the hydrostatic gradient is approximately 8 ppg (hot water). This means that only one point in the reservoir can be balanced with a column of continuous fluid (see **Section 8.7.2**)
- The reservoir is one regional, sub horizontal fault through a granite
  - Zero porosity-permeability except in the fault zone
  - 'Strength' or system resistance of the fault varies with every intersection
  - The range of pressures that can be applied to the fault without losses is narrow and varies

- Existing fractures in the granite are of low long term productivity but have sufficient permeability to create losses/kicks. Fractures may also contain high levels of CO_2 or H_2S which compromises drill fluid
- Tectonically, the area is in compression
  - Wellbore stability issues require maintenance of minimum pressures
  - Breakout causes the open hole to quickly become oval (except close to the fault)
- Low concentrations of Chlorine and H_2S, and high concentrations of CO_2 in the reservoir fluid
- Drilling fluid density is not constant with depth due to expansion of the fluid with temperature
- Wells are subject to extreme pressure and temperature cycles
  - Stimulation creates pressures of 7,000 psi at surface and reduces downhole temperatures to 50°C
  - Production increases surface temperatures to 230°C
  - Load cycle requirements are not clearly defined
  - Trapped fluid increases in pressure as the fluid is heated during production- this is particularly a concern in a completion annulus or free fluid in the cement (cement holiday)
- Wells are drilled under the South Australian Petroleum Regulations rather than a geothermal specific code
  - Wells must maintain compliance with American Petroleum Institute (API) standards including a double barrier policy
  - Well control must be in place before the Cadna-Owie
  - Zonal isolation is required of all potential aquifers and petroleum zones
  - High levels of stakeholder engagement are available from the South Australian regulator as GDY is classified as a high supervision operator

To manage these complexities, drilling EGS wells in the Cooper Basin needs to be undertaken with a high level of diligence. To address these challenges, GDY has instituted practices from the HPHT industry such as downhole modelling and fingerprinting, and from the geothermal industry such as cementing practices, management of thermal cycles and geothermal tools. GDY has also formed strategic partnerships to address the major challenges - key partners have included Blade Energy for engineering support, Packer's Plus and Welltec for completions, Halliburton for Reverse Cementing and competent rig operators.

7.2 Exploration Drilling Results and Learnings

6 wells have been drilled by GDY in the Cooper Basin targeting the Enhanced Geothermal System reservoir. All the wells experienced significant challenges and non-productive time while drilling. One additional well (Celsius 1) was drilled by Origin Energy to target a potential Hot Sedimentary Aquifer resource. The history of the existing wells is summarised in **Table 7-1**.

Table 7-1: Cooper Basin Well Status

Well	Summary
Habanero 1	Drilled: February 15 to September 17, 2003. Total Depth of 4,253 m Well successfully drilled to 4,253 m, intersecting the Habanero main fracture. 6 inch well design was used. A water filled over pressured fracture was encountered at 4,253m. The overpressure of approximately 5,000 psi (34.4 MPa) is unique amongst Enhanced Geothermal Systems projects in granite. After the completion of Habanero 1 the stimulation of the well commenced. The fracture at 4,253m was successfully stimulated. Over 28,000 microseismic events were recorded during stimulation in a shallow dipping plane, i.e. closer to horizontal than vertical, with an areal extent approximately 2.5 km^2, longer in the north-south direction than the east-west direction. Despite the successful stimulation, the injectivity of the main fracture network zone only improved slightly over the period of stimulation. Initial injection tests before any seismicity had been produced showed injection rates of 1 kg/sec/MPa. By the end of the stimulation the injectivity had only improved slightly, in the order of less than 10%. A total of 241 days with 143 days of lost time days. Higher than expected pressures were encountered in the sedimentary and subsequent granite formations below. The BOP Stack had to be changed out from 5k to 10k equipment. The well took a kick when high pressure at a fracture was encountered in the granite. Problems occurred while trying to control the pressure by weighting the drilling fluid followed by lost circulation. The maximum temperature was 247°C, at 4,253 m depth. The last casing was 7 inch at 4,134 m (29 ppf, BTC top 3,031 m, and 32 ppf New VAN bottom to 4,134m). The first packer, plug and tailpipe installed on 4-1/2 inch tubing at 3,109m leaked, and a second packer was installed at 3,096 m with 4-1/2 inch 21.6 ppf SM95S New Vam production tubing to 3,107 m. The injectivity was apparently significantly damaged by the loss of whole drilling fluid into the "main fracture". Final hole size was 6 inch at 4,253 m. Current Status: This well is currently only able to be used for injection as the wellhead is limited to 121°C and the downhole packer is limited to a maximum temperature of 232°C. It has been used as part of the closed loop flow test with Habanero 4. It is currently open and the reservoir pressure is being monitored from surface.
Habanero 2	Drilled: July 2004 – Completed January 2005 Drilled to 4,358 m The Habanero 2 well was again a 6" well design, similar to Habanero 1. Based on the experience of the Habanero 1 drilling campaign a Managed Pressure Drilling system was used. Multiple challenges including loss/kick situations occurred while attempting to drill the main fracture in the open hole section. 4 sidetracks were drilled but were ultimately unsuccessful in establishing connection to the Habanero main fracture. Results: After the first 2 sidetracks, production testing was carried out. A plug placed during suspension could not be retrieved and was pushed to bottom. It is thought this came to rest between an upper steeply dipping fracture and the main fracture. This blockage significantly reduced productivity and it was decided to attempt to sidetrack with a snubbing rig. Wellbore stability issues led to becoming stuck in hole on both sidetracks attempted. With a total of four sidetracks, the well has been suspended. Final hole size: four sidetracks drilled with 6 inch open hole Current Status: Plug and Abandon well completed in 2014.

Well	Summary
Habanero 3	Drilled: 2008 - completed February 2008 Drilled to 4,221 m Total Time on well 147 days: 47 Lost days. The well was successfully drilled and completed without major losses while drilling the main fracture. Drilling through the main fracture was successfully conducted with Managed Pressure Drilling, which was a major improvement over previous wells and included weighting up fluid prior to pulling out of hole which overbalanced the well by more than 500 psi (compared to Habanero 1 where the fracture took losses at less than 150 psi overpressure). Final hole size 8.5 inches In March 2008, the Habanero 3 well was first opened to flow. At surface the flow was 16.5 kg/s and the temperature 207°C. Circulation test (open) with Habanero 1 successfully undertaken and achieved a flow rate of 18.5 kg/s at an injection pressure of 7,400 psi (50.8 MPa). Closed loop testing was undertaken between mid December 2008 through to late Febraury 2009. Maximum outlet pressure achieved was 44.8 MPa and maximum temperature was 212.5°C about the same as achieved in the shorter term open flow tests. The closed loop flow rate achieved was 15.6 kg/s. During closed loop testing, a chemical tracer test was undertaken. The tracer test was successful. The tracers were first detected from the production well after 4 days and the peak of return was around 9 days. The mean residence time was 23.7 days and the fraction of tracer returned was 78%. Maximum temperature of 244°C @ 4,180 m The well was being used in a closed loop flow test with Habanero 1 when the casing failed near surface due to caustic stress corrosion cracking in the annulus. The casing in the top 6m of the well ruptured with water and steam flowing from the well for approximately 25 days before the well as controlled. Current Status: The well is currently plugged and capped. Plans are in place to Plug and Abandon the well in 2015.
Jolokia 1	Drilled: 2008 - 17 March to 14 September 184 days to drill well Drilled to 4,911 m 8.5 inch well design. The Jolokia 1 well was completed to a depth of 4,911m in a relatively uneventful drilling campaign. 48 days Lost Time were experienced while drilling Jolokia 1. There were mainly due to low reliability of rig pumps in 8 ½ inch section and issues running the 18-5/8 inch casing. A shallow fracture was sealed off with cement. Angle picked up in 8 ½ inch section. Drilling in coal sections was complicated and backreaming was required on trips. The well was suspended waiting equipment for a completion with a shallow. The well was re-entered in 2010 to reinstall two new barriers (as original barriers were regarded as compromised with hydrogen embrittlement). Operational challenges were presented in the forms of a) the drilling fluid which appeared to be contaminated by CO_2 from the shallow fracture (initially sealed with cement) causing fluid to gel b) the liner could not be run to depth but what appeared to be a bridge above the fracture and c) the completion set prematurely in the casing which was associated with hausmanite from the cement job coating the casing, running speed and high viscosity fluid. Stimulation commenced in October 2010. Results: The Jolokia 1 well stimulation sharply contrasted to the previous Habanero stimulations only 10 km away. Approximately 200+ microseismic events have been recorded at Jolokia in comparison to over 40,000 microseismic events from the Habanero reservoir. Temperatures are about 10°C higher than Habanero. Final hole size 8.5 inch Current Status: The well is suspended and is considered a candidate for trial of technologies such as fracture initiation or wireline logs that do not need the full wellbore entry.

Well	Summary
Celsius 1	Drilled: 3rd April to 19th May 2011 Drilled to 2,418 m Hot Sedimentary Aquifer exploration well successfully drilled to target depth. Issues with Celsius 1 include rig down time, wireline logs and DST could not be run in production hole due to poor hole conditions in the Winton. 8-1/2 inch was drilled to 2,418 m and 7 inch casing was landed 200m above section TD (to expose the Hutton sandstone) in attempt to obtain DST. Cement slumped into Hutton formation and open hole was perforated to bypass. Second DST failed mechanically Results: DST gave a calculated permeability thickness for the Hutton Sandstone of between 0.98–1.6 mD.ft. This result is not sufficient for geothermal production. Final hole size 6 inches Current Status: Plug and Abandon was completed in 2014.
Savina 1	Drilled: October 2008 – Mar 2009 Drilled to 3,700 m 8.5 inch well design. The 12-1/4 inch section of Savina 1 was drilled underbalanced- ROP was improved but time lost managing kill mud system offset the cost savings. Well kicked at 3,700 m and BHA became stuck while regaining control of the well. While drilling the section, hole problems of formation stick and slip, drag, erratic torque were observed. Other delays were caused by multiple mud pump failures, power failure to the rig, change in plans for kick off etc. Granite section was also to be drilled by UBD in anticipation of abnormal pressure as seen in previous wells during drilling out fractures. Following stuck BHA, cement plug was placed and dressed for kick-off. Results: High permeability zone encountered within the granite (kick) but was not tested and is significantly shallower than at Habanero. Final hole size: 12 ¼ inches Current Status: Plugged back with 4 cement plugs and suspended ready for sidetrack.
Habanero 4	Drilled: March - September 2012 Drilled to 4,225 m 8.5 inch well design This is the first well to address Habanero 3 failure mechanisms- mitigations included low grade casing, non-marking tong dies, completion to isolate from stimulation loads and the reverse cement job to ensure cement at surface was set. The reverse circulation cement job was successfully conducted on 9-7/8 inch production string set at 4,025 m. A major challenge was drilling through the main fracture without loss of whole drilling fluid. This was successfully achieved through use of downhole pressure modelling with SPT software and careful management of drilling process. A local stimulation was conducted to improve the connection between the Habanero 4 well and the reservoir. The stimulation produced ~1,900 micro-seismic events. Completion barrier compromised during cool-down of stimulation process. Annular pressures initially varied significantly but are being managed with nitrogen cap between 9-7/8 inch and 7 inch casing (also test of nitrogen as insulation). Significant lost time due difficulty running casing past duracrust, a stuck plug in the BOP, and drilling out excess cement after reverse cement job. Results: This is the most productive well drilled in the field. Successful local and large stimulation treatments were conducted with pressure at or below 7,000 psi at wellhead. Maximum flow rate has not yet been determined but it is above 40 kg/s. Well successfully operating in conjunction with Habanero 1 as injection well to undertake the Habanero Pilot Plant commissioning and trial. Prior to closure of trial, the plant was operating at 19 kg/s and 215°C production well-head temperature. Final hole size of 8.5 inches open hole. Current Status: The well is currently open with pressure monitoring of the reservoir from surface measurements.

7.2.1 Key Lessons Learnt

7.2.1.1 Drilling the Fracture

A major challenge for drilling and completing wells in the Cooper Basin was successfully drilling through the main fracture in the granite reservoir. When Habanero 1 was drilled the overpressured reservoir was not anticipated. When the fracture was encountered production brine entered the wellbore causing gelation of the drilling fluid. Attempts to control the flow by increasing the density of the drilling fluid resulted in too much pressure being applied and losses of the drilling fluid. In the end a large volume of drilling fluids and associated solids were permanently lost to the main fracture resulting in significant reduction in permeable flow.

Habanero 2 had multiple problems drilling through the fracture and the well had to be abandoned. Habanero 3 was successfully drilled but the well subsequently failed due to incomplete cement coverage in the production string annulus. It is believed that the reason why Habanero 3 was successfully drilled through the fracture was at least partially due to a difference in the "fracture strength" or ability of the fracture to withstand a higher amount of pressure above the pore pressure before it broke down. It may simply be that the fracture strength was greater in the location where Habanero 3 was drilled than where Habanero 1 and 2 were drilled.

Habanero 4 was drilled successfully without incident through the main fracture. Significant engineering was done to ensure the best possible modelling of downhole pressure was obtained. The density of the drilling fluid was measured as a function of both pressure and temperature. The variation in density of the drilling fluid when exposed to very high downhole temperatures and pressures was found to be as high as 1.2 ppg. In addition, rheological properties of the drilling fluid were obtained at downhole temperatures and pressures, and were found to be significantly different than what is measured at surface temperatures and atmospheric pressure. SPT used this information and calibrations while drilling to provide fluid modelling to carefully predict downhole pressure fluctuations. The properties of the fracture were determined when the fracture was penetrated by a dynamic pressure test. This test was conducted by increasing and decreasing circulation rate of the drilling fluid, changing the downhole pressure by changing the amount of friction pressure in the system, until slight losses and slight gains were detected. These pressures were then used with the SPT models to define the placement procedure of the kill weight mud while tripping out and to limit the drilling fluid density, flow rates and tripping speeds of subsequent operations.

As a contingency for Habanero 4, a sized calcium carbonate lost circulation pill was developed, tested and pre-mixed on site in case uncontrolled losses occurred while drilling through the main fracture. The plan was to pump the LCM pills in an attempt to seal off the fracture. If use of the LCM pills proved ineffective the next contingency plan was to "sand back" the open hole up to the fracture with sized calcium chloride. This material could subsequently be removed by circulating the material out with a coiled tubing unit.

For all future wells the technical challenge should not be ignored or minimised. Failure at this point can result in total loss or significant damage to permeability damaging the useful productivity or injectivity of the well. This risk is reduced by use of CT drilling with brine as this allows fluid loss or influx without danger of damaging the formation or causing drilling problems as in previous wells. In addition to this, it is recommended that the same level of modelling and planning is applied in future wells to prevent or minimise losses to the main fracture. A contingency of a lost circulation sealing system like sized calcium carbonate should also be part of the plan.

7.2.1.2 Well Integrity

One of the key learning's from drilling and producing Habanero wells was the importance of well integrity. Habanero 3 had a casing failure in April 2009 in which several casing strings failed near the surface. After comprehensive investigations it was concluded that the failure was due to caustic

stress corrosion cracking due to presence of high pH from unset cement in the annulus behind the 9-5/8 inch casing. Contributory factors were a) selection of high tensile strength material (150ksi) that was susceptible to hydrogen embrittlement and caustic cracking, b) the cyclic loads which concentrated the annular fluid through boiling off and broke the passivating corrosion layer and c) tong marks which became the initiation point.

To ensure that the Habanero 3 failure could not be repeated the following modifications were recommended:

- Select metallurgy of the 9-7/8 inch casing string with lower tensile strength that can pass NACE recommended Fit-For-Purposes tests. This eliminates the risk of hydrogen embrittlement and makes the material less susceptible to caustic cracking;
- Eliminate fracture initiation points by use of non-marking dies and tighter casing specifications;
- Eliminate cyclic loads on the production casing by use of a completion (note this recommendation has been subsequently reconsidered following the learnings of Habanero 4, see 7.2.1.4); and
- Eliminate the caustic environment by ensuring that the cement is set at surface.

Technically, well warming is not required on the GDY wells as the traditional reasons for this are engineered out or the environment is sufficiently different that failure mechanisms such as chlorine cracking are not a concern. The need for well warming is eliminated by a casing design that is able to withstand all loads even if not cemented, ductile cement able to comply to the changes in diameter of the casing and designing casing to maintain loads below the level that metal fatigue sets in. Despite this, well warming is associated with an extended well-life in New Zealand, and as such is recommended to be employed at Habanero. This should consist of a reduction of thermal cycles by a maintaining low production flows during short duration shut downs, and reducing thermal stresses by slow well warming processes on start up from cold conditions.

7.2.1.3 Cement

On Habanero 3, the unset cement near the surface of the 9-5/8 inch casing was due to the fact that cement had to be circulated past the high temperatures at the bottom of the 4,000 m production string. To safely circulate cement at these high temperatures, the addition of large amounts of retarders were required. While the cement at the bottom of the string was able to set normally after placement, the cement at the top of the column was not able to set. To prevent this failure from occurring again the procedure to place the cement was changed. Instead of circulating the cement down the casing and back up the annulus the cement was circulated in the opposite direction - down the annulus and back up the inside of the casing. This allows retarder concentration to be tapered as a function of depth so that all the cement is designed to set up in its final placement depth. Through the use of this reverse circulation cement methodology, Habanero 4 successfully achieved set cement in the upper portion of the production casing.

In addition to having set cement throughout the entire column of cement, it is also important that there are no pockets of free water, caused by solids settling in the cement slurry, in the cement column. Pockets of "free water" can lead to casing failure if they occur in the confined space between casing and casing. As the temperature increases significantly, the trapped water is unable to expand and dramatically increases in pressure which can cause the inner casing to collapse. To prevent free water the cement slurry must be designed with special attention paid to the solids suspension properties.

In a similar manner, "cement holidays" or pockets of un-displaced mud can have the same effect if they occur between two casing strings. The water in the un-displaced mud will also expand when temperature increases during production. To prevent mud channels, factors affecting mud displacement must be considered carefully. For Habanero wells the following should be considered:

- Ensure that mud is properly conditioned and progressive gel strengths are minimised and kept "flat"; i.e. they to not increase rapidly when the drilling fluid stops moving.
- Minimise and/or prevent shut downs between conditioning of the drilling fluid and pumping the cement spacer and cement slurry.
- Pump fluids as fast as possible. If batch mixing is used rates should be varied rather than kept constant so that periods of maximum pump rate occur along with periods of slower pump rate. During the high rate time periods, pockets of mud will be more likely to be displaced than if the rate is kept slower and constant throughout the job.
- Changing the size of the hole and casing from 9-5/8 inch casing in a 12-1/4 inch hole to a 7 inch casing in an 8-1/2 inch hole will greatly aid in the mud displacement process because the linear fluid velocity will increase significantly at a given pump rate in the small sized geometry.

7.2.1.4 Completion

Installing completions in the Habanero wells is particularly difficult and as such are avoided in the FDP well designs. Complications have occurred in the installation of the completion on all occasions that it has been attempted in the GDY Cooper Basin wells. Despite this, a completion was installed on Habanero 4 as one of the mitigations against a repeat of the Habanero 3 failure. The completion was intended to isolate the production casing from the cyclic loads created by the stimulation and the thermal changes from alternating between stimulation, standby and production temperatures. In reality, the closed annulus volume created large pressure swings as the trapped fluid attempted to expand with temperature and, if not mitigated with Annular Pressure Management, created loads larger than those it was intended to avoid.

During the flow tests on Habanero 4, pressure communication occurred between the 7 inch annulus and the production tubing. It is believed that the most likely cause of this was failure of seals in the Polished Bore Receptacle (PBR). These seals were tested at high temperatures but were not specified for the low temperatures experienced during stimulation. For the FDP wells, a completion string is not planned. The well has been designed to provide a double barrier through the strength of two cemented casing strings. If the insulation option is required, a single fixed pressure barrier will be combined with a removable corrosion barrier. Removing the completion also creates a significant cost saving as the additional casing string (production tubing), the mechanical packer and the PBR assembly are expensive.

7.2.1.5 Equipment Reliability

The importance of rig reliability increases with depth. Key concerns are:

- Drilling Fluid System
  - High levels of solids retention has previously lead to contaminated drilling fluid and damage to the pumps.
  - Consistent pump performance is required to maintain the finger-printing repeatability required to detect kicks.
  - Primary well control is maintained by the Equivalent Circulating Density (ECD) of fluid at a fixed flow rate and the mud density at a stable temperature profile - any pump down time or variations in flow rate alter the temperature profile and complicate maintenance of overbalance conditions.
- Drill pipe
  - It is recommended that larger drill pipe, such as 5-1/2 inch as opposed to a more standard size of 4-1/2 inch, is used as this has been effective in minimizing vibration issues and greatly improves annular velocity and hole cleaning while drilling.

- Inspection Standards: previous wells encountered multiple problems with DP being substandard before it arrived on site. This can be prevented by ensuring that tubulars meet a minimum spec of DS1 Cat 3 – 5.
- Connections: these need to be a Hi Torque dual shoulder type connection.

7.2.1.6 Use Down-Hole Parameters in Models

The rheological properties of the drilling fluid can change significantly as a function of temperature and pressure. Conventional methods of measuring the rheological properties of drilling fluid involve using only surface pressure and temperature measurements. For Habanero wells a significant portion of the well is drilled where both static and circulation temperatures exceed 100°C. Therefore, to accurately model aspects of drilling and predict downhole fluid behaviours it is important to obtain rheological data for drilling fluid at both downhole pressure and temperature.

It was learned that it is a particularly critical issue to have accurate rheological data when engineering the process of drilling through the main fracture in the reservoir. Accurate downhole pressure predictions are dependent upon accurate rheological properties of the drilling fluid over a wide range of temperature and pressure conditions. It is also known that both the rheology and the density change significantly as a function of temperature. The consequence of not having accurate prediction of downhole pressure while drilling through the open hole main fracture is that drilling fluid may be lost into the fracture resulting in significant damage to production and/or injection, or that an influx of reservoir brine may occur causing significant operational problems, or both.

For the placement of cement and displacement of the drilling fluid it is also important that correct rheological properties are used. Prediction of maximum circulation pressure downhole is dependent upon both the density and rheology of the fluids. While modelling the Habanero 4 reverse cement job using surface rheology values of the drilling fluid for modelling the downhole pressure, it originally appeared that the circulation pressure at the last casing shoe was close to the fracture gradient. This brought into question whether the reverse circulation cement job was technically possible. When the downhole drilling fluid rheology was used, the circulation pressure prediction was greatly reduced and the feasibility of the method was confirmed.

7.2.1.7 Casing Design

Casing design of the Habanero EGS wells is complicated and challenging. An overly conservative well design quickly becomes operationally unmanageable due to:

- Extreme wall thicknesses that create material variability due to heat treating issues;
- High casing string weights increasing rig size requirements and decreasing efficiency;
- Complicated placement techniques to lock in initial conditions (casing tensions); and
- Multiple liners and tie backs (as per Jolokia 1).

A level of well integrity needs to be obtained that balances conservative working stress design and operational requirements. To achieve this, GDY has developed technical standards that provide guidance on applying Reliability Based Design when a satisfactory working stress design cannot be obtained. GDY endorses level 4 Reliability Based Design. This design methodology uses a detailed understanding of the quality variations in the specified casing to create a probability curve of the material properties. These are then compared with expected loads as per Working Stress Design (i.e. it is assumed that loads do occur and that they occur at the same magnitude as specified in Working Stress Design) and the probability of entering a yield phase or casing failure is calculated. Other issues that need to be considered when designing casing strings for Habanero wells include:

- Fatigue failure from cyclic loads – cyclic loading becomes an issue when exceeding 90% of yield strength.
- De-rate material for temperature.
- Fixed point analysis on casing connections.
- Surface Casing designs may require that material is allowed to enter yield phase during production.
- Annular Pressure Build-up analysis in line with the New Zealand Deep Geothermal Wells standard to ensure the production casing does not fail if there are pockets of 'free water' trapped between two casing strings.
- Dog Legs - Tolerance for doglegs is low in the top hole section.

7.2.1.8 Metallurgy

Production casing material for geothermal wells has to be designed for two different environments: the produced reservoir fluid, and the annulus.

The first environment is the reservoir fluid inside the casing with low levels of H_2S, high levels of CO_2 and chloride in solution. This environment can cause sulphide stress cracking in some high tensile strength steels when the temperature is low. Under normal producing conditions sulphide stress cracking is not an issue, however it needs to be considered when wells are on standby and for the injection well. Material options that have been qualified include T95 (95 ksi yield) and Sour Service TN110SS (110 ksi yield). There is literature data that supports the application of Sour Service 125 ksi grade from certain suppliers. Maintaining the well in a 'warm' state (above 110°C) can also prevent sulphide stress cracking in the production well if high tensile strength material has to be used, however this is not recommended as failure of surface equipment or operational procedures would jeopardise the well.

The second environment is the annulus outside the casing. The worst case is a very high pH environment if the cement does not set in the annulus. The high pH environment poses a risk for caustic cracking at higher temperatures. This was identified as the primary cause for the failure in Habanero 3; where the 150 ksi non-sour service casing material was used. Recent testing in high pH environment demonstrated the 150ksi material lacks adequate resistance to cracking in the caustic environment. This was in contrast to the behaviour exhibited by the 110 ksi material; which demonstrated adequate resistance in the high pH environment at the high temperature.

Consequently, design of the production casing material should incorporate resistance to both environments. The 110 ksi material has demonstrated resistance in both environments and is applicable for all future wells. In literature studies, the 125 ksi material has demonstrated resistance to the sour environment, but would require further verification in the high pH environment.

7.2.1.9 Corrosion

There are three separate conditions that need to be considered for corrosion:

1. Production - at production temperatures, initial corrosion creates a passivating layer of iron carbonate and continued corrosion is very low.

2. Injection - corrosion rates peak between 60°C and 80°C (See **Figure 7-3**). At the injection temperatures of 90°C, as applied at Habanero 1, corrosion is highest at surface and gradually decreases as the fluid warms up with depth. Recommended corrosion allowances are 12 mpy for general corrosion and 20 mpy for pitting corrosion. At these corrosion rates, normal carbon steel materials are sufficient. A passivating layer can be created in injection wells by flowing

for a period at high temperature. This could be during initial flow testing or could be done deliberately later in the life of the well if corrosion is higher than expected.

3. Suspended wells - when these wells are shut-in a fixed inventory situation is created. Without flow, the H_2S and CO_2 components of the well are quickly consumed in corrosion reactions and are not replenished. Following the initial corrosion, the pH increases and the protective iron carbonate layer continues to grow and continues to reduce the corrosion rate. If there is no replenishment, iron carbonate becomes saturated, there is no further increase in pH and the corrosion will eventually stop.

7.2.1.10 Operational Preparation

Contingency planning and crew training are vital to the success of these wells. This is critical as reactions that are normally trained into rig crews, particularly surrounding well control, are not appropriate for HPHT wells. It is recommended that in addition to the standard Risk Assessment and Drill Well On Paper (DWOP) review sessions; training is provided in HPHT practices, including finger printing, and that contingency plans for envisaged problems are prepared and communicated in advance.

7.3 Basis for Design

The challenge of the FDP was to design the lowest cost, high integrity well with low risk of damaging the fracture. The following key parameters guided the well design:

- Vertical wells
- NACE Region 2 Sour service well, assumes reservoir fluid with:
  - Worst case scenario of equivalent H_2S partial pressure of 0.477 psi
  - Environmental pH value higher than 4.0
  - CO_2 partial pressure of 174 psi
- 15 year well life
- Stimulation in both wells (duration longer in injection wells)
  - Maximum pressure of 7,000 psi surface (decreased from 10,000 psi at Habanero 4)
  - Minimum temperature at bottom during stimulation of 40°C
- Maximum production temperature of 230°C (significantly lower than Habanero 4 design)
- Minimising damage to the fracture is the key priority
- Minimum pressure to be maintained to prevent wellbore collapse of 58 MPa.

7.4 A Single Well Design

GDY has given consideration to an SPI (Stimulators, Producers, Injectors) field development with separate well designs for each of a stimulation well, a production well and an injection well. Investigation has shown that there is no apparent benefit to developing separate well designs for the production and injection wells. A single well design is recommended for development of the Habanero field. This decision is driven by:

- The separate stimulation well was initially envisaged to save applying the additional pressure difference between a small and a large stimulation job (estimated as an additional 3,000 psi above the small stimulation estimate at 7,000 psi) to the production and injection wells. The reduction in the maximum pressure for stimulations, combined with the need to maintain ability to stimulate in production and injection wells, means that a stimulation specific well has lost this benefit.
- Although the mechanism is different, both the production and injection wells need to be designed for extreme axial loads. Both production wells and injection wells will be stimulated which creates extreme axial stress loads (even with decrease in stimulation pressure). This load is larger in the injection well which are planned to have extended stimulations. The production wells experience higher axial loads during operation due to the much higher temperatures near the surface from the high temperature production brine.
- Corrosion allowances are similar in both injection and production wells. Initial modelling indicating that the injection well would have significantly higher corrosion because the passivating layer created in the production wells would not be created in the injection well. This was not borne out with further modelling or calliper logging in Habanero 1.
- Multiple well designs result in additional costs in the design process and creating more complexity during a drilling campaign, which is undesirable.
- Flexibility to switch wells from producers to injectors is retained. This is not planned but may be beneficial over the life of the field to try improving efficiency or for other unforseen reasons.

7.5 Existing Assets

Of the four wells existing in the location of the FDP, only Habanero 1 and Habanero 4 are recommended for inclusion in the Field Development. The other two wells, Habanero 2 and Habanero 3, are slated to be Plugged and Abandoned in the near future.

Habanero 1 was utilised as the injection well in the 1MW production trial. This well was 10 years old at the time of the trial. Well integrity concerns with Habanero 1 include BTC connections in the production casing, potentially damaged landing nipple from fluid leaking past the plug (plug was removed prior to the 1MW trial), stibnite deposition inside the tubing and concerns on corrosion of the production tubing. Well integrity was assessed prior to injection in the 1MW trial through corrosion modelling, calliper logging and annular pressure testing to ensure the fluid tightness of the BTC connections. The corrosion modelling indicated that the Habanero 1 production tubing would be able to withstand injection loads for another 8 years. Habanero 1 can only be used as an injector due to temperature restrictions of 150°C in the tubing hanger (Double S seals) and 120°C in the A section of the wellhead. Injectivity in Habanero 1 has been compromised by the small tubing size and a ‘mud ring’ created due to losses of drilling fluids while drilling. Injectivity did gradually improve during the 1MW trial and could possibly be improved further by upsizing or removing the tubing, chelating treatments to remove the mud ring, flowing the well or deflagration.

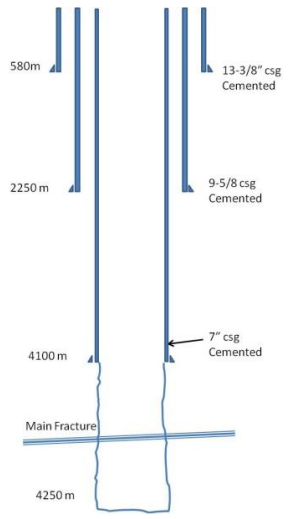
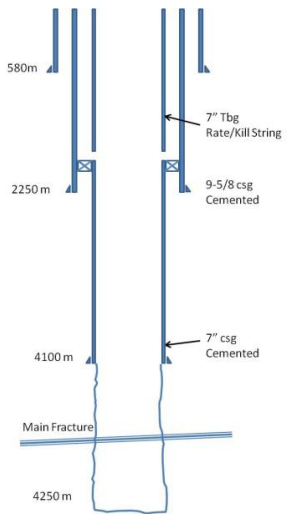
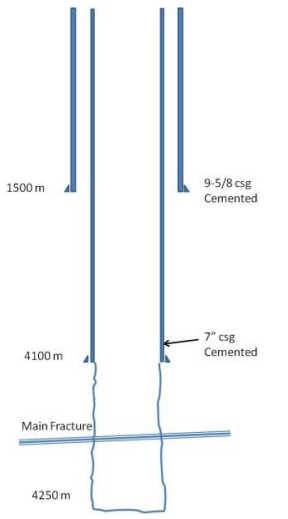
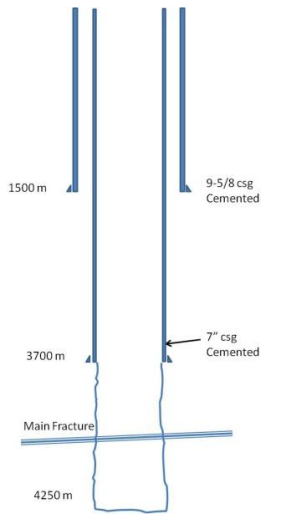
Habanero 4 was utilised as the production well in the 1MW production trial. A failure of the completion to hold pressure meant that throughout the majority of the trial the well was operating with only 1 barrier, but the completion would have acted as a flow restriction if this barrier failed. To utilise Habanero 4 in the FDP; the well will either need to be used as an injection well or dispensation sought to continue using the well as a producer with reduced barriers. If Habanero 4 is used as an injection well, two pressure-containing barriers are in place as the 13-3/8 inch casing is able to hold the expected pressures when not de-rated for the high temperatures experienced in production.

7.6 Well Engineering

7.6.1 Well Concept

Preliminary concept selection work on a Habanero Development design produced 17 options for consideration. The goal of simplifying the well design while maintaining a highly reliable wellbore was paramount. Four well designs were selected for further analysis. These are presented in **Table 7-2**.

Table 7-2: Well Design Options

3-String Design	3-String with Insulation	2-String Design	2-String with CT Drilling
			
Similar to Habanero 2 - a small diameter 'monobore' design	Rate string to enable insulation to be placed behind tubing. Tubing also acts as a removable corrosion barrier	Eliminate a casing string. Surface casing set to install BOP before Cadna-owie (SEO).	Protect fracture and decrease costs by using Coil Tubing. Casing seat as shallow as possible to isolate aquifers (SEO).

The fourth option is the recommended design. This well is a step change from previous wells in that only two casing strings are utilised (there have been 3 strings in offset wells) and that Coil Tubing (CT) is proposed for drilling the fracture. Both casing strings are to be cemented to the surface with the reverse cementing techniques. The granite section will be left open with no completion installed. The production casing shoe has been raised as far as possible while also maintaining the formation isolations required to comply with the Statement of Environmental Objectives (SEO).

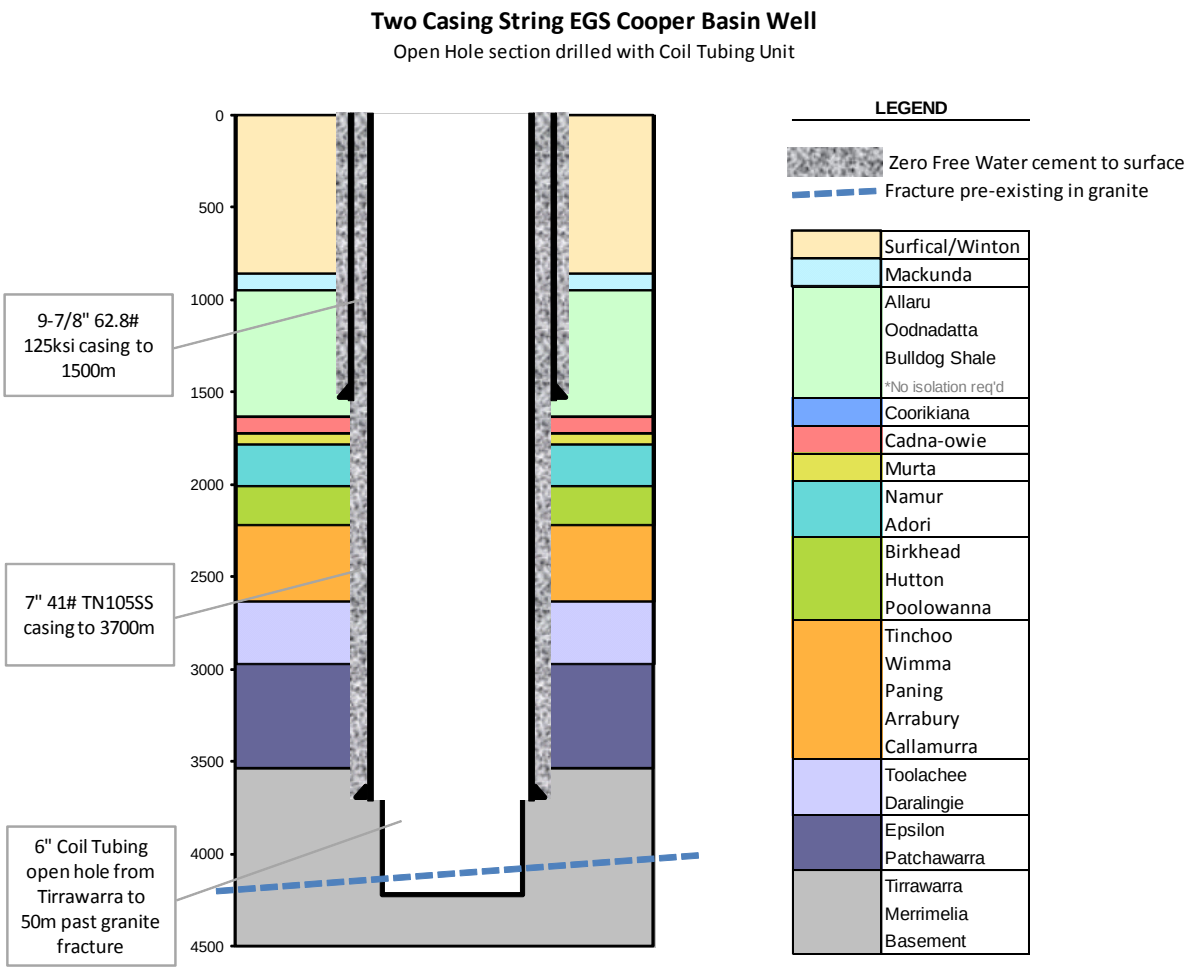


Figure 7-2: Recommended well design - 2-String with Coil Tubing Drilling

7.6.2 Casing Design

The casing design calculations centred on assumptions based on known conditions from Habanero 4, temperature simulations using WellCAT and metallurgical testing. Casing design was completed for all the well design options. The challenge is to design for the stimulation loads created by the cold fluid being injected at 20 bpm with 7,000 psi surface pressure as well as the hot shut-in load created during long term production. The modelling focused on working stress design with design factor criteria shown below in **Table 7-3**.

Table 7-3: GDY Design Factors for Working Stress Design

Load	Required Safety Factor
Burst	1.1
Collapse	1.0
Tension	1.3
Compression	1.0
Tri-Axial	1.25

At the conclusion of the preliminary design work, the 2-String Option is recommended for detailed development. This design utilizes two fully cemented long strings to reach Target Depth (TD). Each is capable of withstanding the high tri-axial stresses created by the hot shut-in load, which delivers

on the requirement to provide two working stress designed barriers. It however, does not meet the best practice of having one removable barrier. This issue will require resolution should the project progress. The current calculations resulted in the following casing design:

Table 7-4: Casing Design for the 2 Casing String Well

Casing Seat Depth (m)	Hole Diameter (in)	Casing Diameter (OD in)	Casing Weight (ppf)	Casing Grade	Limiting Load and (SF)
1500 m	12-1/4 inch	9-7/8 inch	62.8	TN125SS	Production Hot Shut-In at 40 kg/sec transferred from failure of 7 inch (Triaxial SF=1.27)
4100 m	8-1/2 inch	7 inch	41	TN110SS	Cold Fluid Stimulation at 20 bpm with 7,000 psi surface pressure (Tensile SF = 1.34)

The casing design for the recommended CT drilling design is a subset of the 2-string well design and is also satisfied with the above casing grades. If the 2-String Option is eliminated in the future; 3-String and 3-String with Insulation options also passed the preliminary design check.

Casing seats have been chosen to be in compliance with the SEO such that the BOP must be in place before the Cadna-Owie and the Tirrawarra-Merimillia-Granite package is to be isolated from the Patchawarra. The long term stability of the Tirrawarra and Merimillia for open hole completion needs to be reviewed in the detailed design phase. If this is not satisfactory, the casing will need to be set 20 m into the granite. If the deeper casing seats required to deliver a 2-String design are not accepted in detailed design the fall backs are:

- The 3-String design which is approximately $2 million per well more expensive than the 2-string design, or
- The combination of a deeper conductor and a diverter while drilling the 12-1/4 inch hole section

Tenaris Blue connections are recommended. These connections are not qualified for the service but have been robust in the field.

The preliminary casing design check was meant to give an idea of the technical feasibility of each design premise. As a result, a large number of assumptions were made about conditions known to heavily influence strength and load calculations. It is recommended that in accordance with GDY's "Well Engineering Management System Description and Processes" (WEMS), additional rigor be applied to the design before it is considered final as additional cost savings in casing weight or grade may be possible. Additional work required includes:

- Confirm pore pressures and fracture gradient curves and well as a geologic prognosis at the actual well location.
- Conduct detailed temperature simulations during injection and production for 2-String Option at different flow rates.
- Model expected surface pressures during injection at different injection rates.
- Complete the corrosion study to qualify TN125SS.
- Conduct APB analysis on the 9-7/8 inch x 7 inch annulus.
- Determine corrosion allowances and calculate well-life using general corrosion of 12 mpy and pitting corrosion of 20 mpy in the injection well.

7.6.3 Material Selection

The importance of correct metallurgy choices was highlighted by the failure of Habanero 3. Although the well failure was caused by a combination of caustic cracking and cyclic operational activities, the investigation did highlight the possibility of failure by other mechanisms. Significant work has been undertaken to understand the fracture mechanics behaviour of the casing material in the Cooper Basin reservoir environment. The three key cracking mechanisms to be considered are:

1. Material susceptibility to H_2S, CO_2 and pH - NACE standard MR0175 specifies approved materials for different levels of sour service and where possible GDY uses compliant material in casing designs. The Cooper Basin reservoir is classified as NACE Region 2 sour service. Unfortunately the NACE prequalified materials have relatively low strength and are rarely able to be utilised in Habanero casing designs. To use higher grade materials, MR0175 requires a thorough understanding of the material resistance to fracture initiation and propagation. This can be obtained through Fit-For-Purpose testing in simulated reservoir fluid environments for each batch of non-NACE complaint casing ordered. GDY has successfully applied this methodology to TN110SS. The Pressure Allowable Limits as calculated from this testing are presented in **Table 7-5** for the casing sizes in the recommended well design. These limits are conservative but have been based on only two heats of material. It is recommended that a qualification test is conducted on each casing batch used in future wells. Other operators are known to have successfully applied this methodology to 125 ksi material at similar environmental conditions.

Table 7-5: Pressure Allowable Limits (PAL) for relevant TN110SS casing as a Function of Flaw Depths (infinitely long) in 2.0 psi H_2S NACE test solution B environment

OD (in)	Weight (ppf)	Wall (in)	Burst Pressure for Flaw Depth 5%, psi	Burst Pressure for Flaw Depth 12.5%, psi	Burst Pressure for Flaw Depth 17.5%, psi
7	41	0.59	9,958	6,135	5,043
9-7/8	62.8	0.63	7,375	4,530	3,713

2. Material susceptibility to caustic conditions – the Habanero 3 well failure was created by the effect of a highly caustic environment on V150 material. Recent experimentation into the relative susceptibility of casing material to highly caustic environments (simulated as 20% NaOH), has shown that with an existing notch of 5% of wall thickness, the 9-5/8 inch V150 casing used at Habanero 3 would fail in a highly caustic environment if exposed to shut-in well pressure (5,000 psi). In comparison TN110SS material under the same conditions would maintain ability to contain reservoir pressures up to a flaw depth of 11%. While the preferred methodology to prevent a reoccurrence of this failure method is the elimination of the caustic environment; it is recommended that the lowest feasible yield strength material is also used to decrease the susceptibility to caustic cracking. If 125 ksi material is used, susceptibility to caustic cracking should be determined experimentally. In addition, additional focus should be placed on eliminating the caustic environment by using reverse cementing; preventing high temperature cycles and annular bleed down, which allows boiling off and concentrates annular fluids; and ensuring the casing is delivered to a sufficient quality standard and is unmarked on arrival at site or while running in hole.

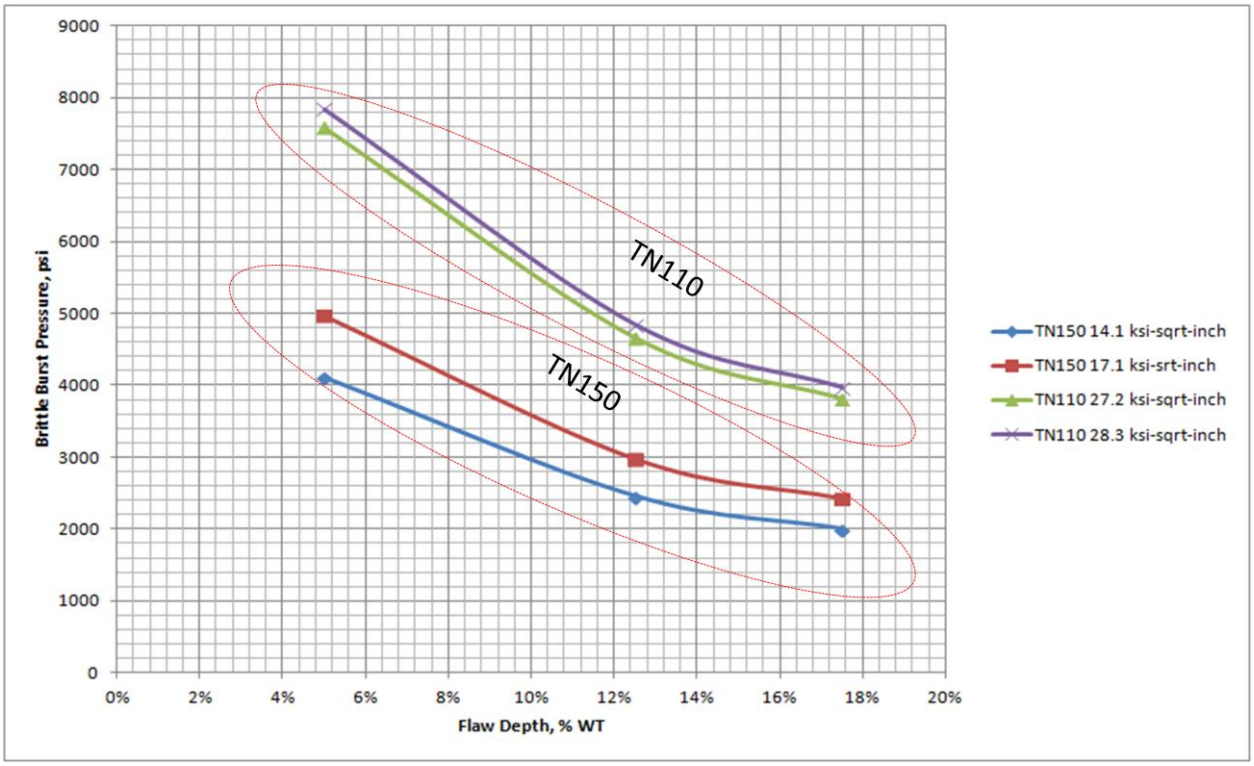


Figure 7-3: Pressure Allowable Limits (PALs) of 9.625 inch OD × 0.472 inch WT TN110 & TN150 casing as a function of flaw depths (infinitively long) in 20% NaOH Solution

3. Material susceptibility to chlorine cracking - NZ2405 recommends that production wells are maintained in a warm condition when not in operation by maintaining a small bypass or 'well bleed' system. A key reason for this recommendation is that the typical New Zealand geothermal reservoir is sub-artesian and chlorine and other gases are able to devolve from the reservoir fluid and concentrate at the wellhead if the well is allowed to cool. This is not a concern in the Cooper Basin as the bubble point of the Habanero reservoir fluid is significantly lower than the 5,000 psi over pressure that is seen in suspended wells and the gases of concern are not produced.

7.6.4 Corrosion

Corrosion has been modelled in the OLI thermodynamic/corrosion software package. The pH under downhole conditions is 5.2. The corrosion rates in carbon steel with a flowing fluid similar to Habanero 3 are presented in **Figure 7-5**. Corrosion peaks at 52 mpy (1.3mm/year) between 60°C and 80°C and then steadily drops to 0.006 mpy as temperature increases. In the closed loop system this equates to low corrosion in the production well and moderate corrosion in the injection well.

The declining trend of the corrosion rate is a function of increasing temperature, decreasing CO_2 solubility and increasing protectiveness of the corrosion product layer on the surface of the metal as the temperature increases. The reasons for these low corrosion rates (compared to systems with high CO_2 partial pressures) are: a) the presence of H_2S and b) the fact that the produced water appears to be scaling. In the absence of H_2S, predicted corrosion rates are almost two orders of magnitude higher. This makes it imperative to understand the origin of H_2S in geothermal wells and resolve the question as to whether continued presence of traces of H_2S will be assured in the future.

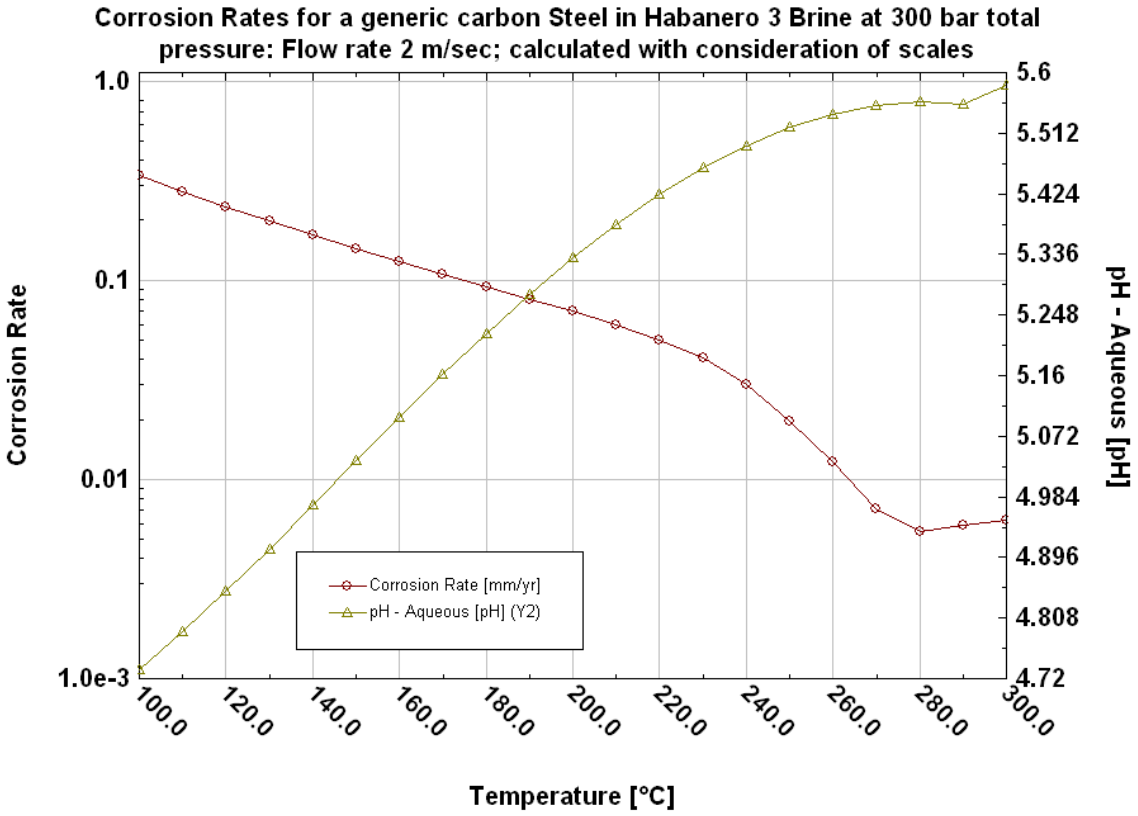


Figure 7-4: Corrosion Rates for a generic carbon Steel in Habanero 3 Brine

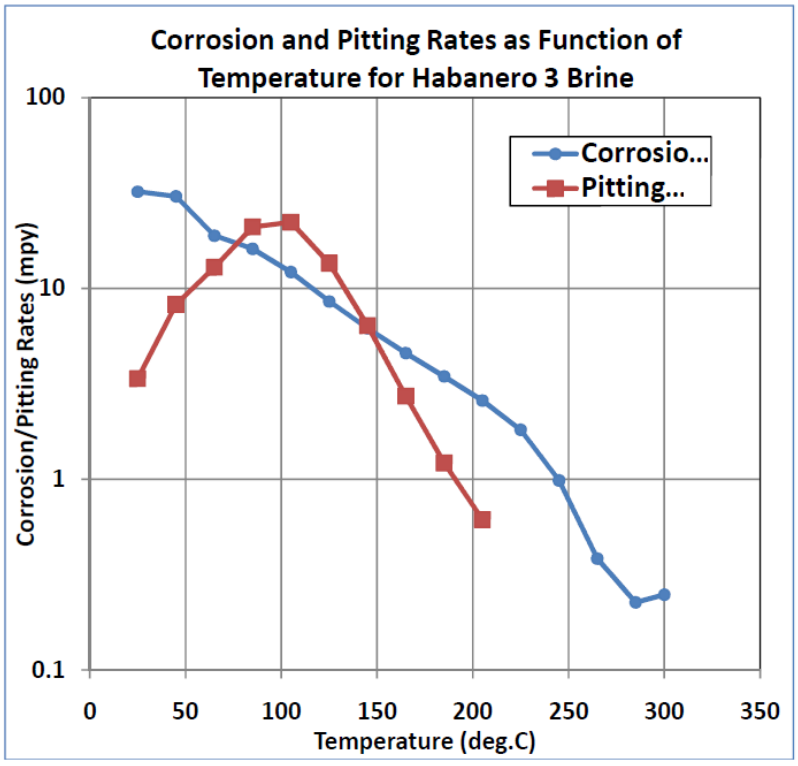


Figure 7-5: Corrosion and Pitting Rates as a Function of Temperature for Habanero 3 Brine

For the injection well, the recommended allowance for general corrosion is 12 mpy (0.3 mm/year) and pitting corrosion of 20 mpy (0.5 mm/year). The results of this modelling were found to be reasonably similar to the caliper run obtained in Habanero 1 prior to the closed loop circulation in

2013 except for an anomaly at 3,000 m. The predicted corrosion with depth in an injection well with a surface temperature of 90°C is presented in **Figure 7-5**. The recommended general corrosion allowance for the production well is 4 mpy (0.1 mm/year). This rate is conservative but is selected to allow for significant reduction in production temperature in late field life. There will most likely be no pitting in the production well (at temperatures above 210°C).

There had been a concern that the shut in of an injection well would lead to low temperatures at the well head and therefore to high corrosion rates as are common in systems at high CO_2 partial pressures. Analysis of this situation however led to the realization that a well full of "stagnant" CO_2 containing water resembles the laboratory conditions of constant inventory corrosion tests which is common in most laboratory investigations. Shut-in wells will create a fixed inventory situation in which the H_2S and CO_2 of the well are quickly consumed in corrosion reactions and without flow; the H_2S and CO_2 are not replenished. Following the initial corrosion, the pH increases and the protective iron carbonate layer continues to grow and continues to reduce the corrosion rate. If there is no replenishment, iron carbonate becomes saturated, there is no further increase in pH and the corrosion will eventually stop. This is demonstrated in **Figure 7-6**. The experimental autoclave results replicate a fixed inventory (shut-in well) condition and the corrosion rate can be observed to rapidly drop with time as the CO_2 and H_2S are consumed.

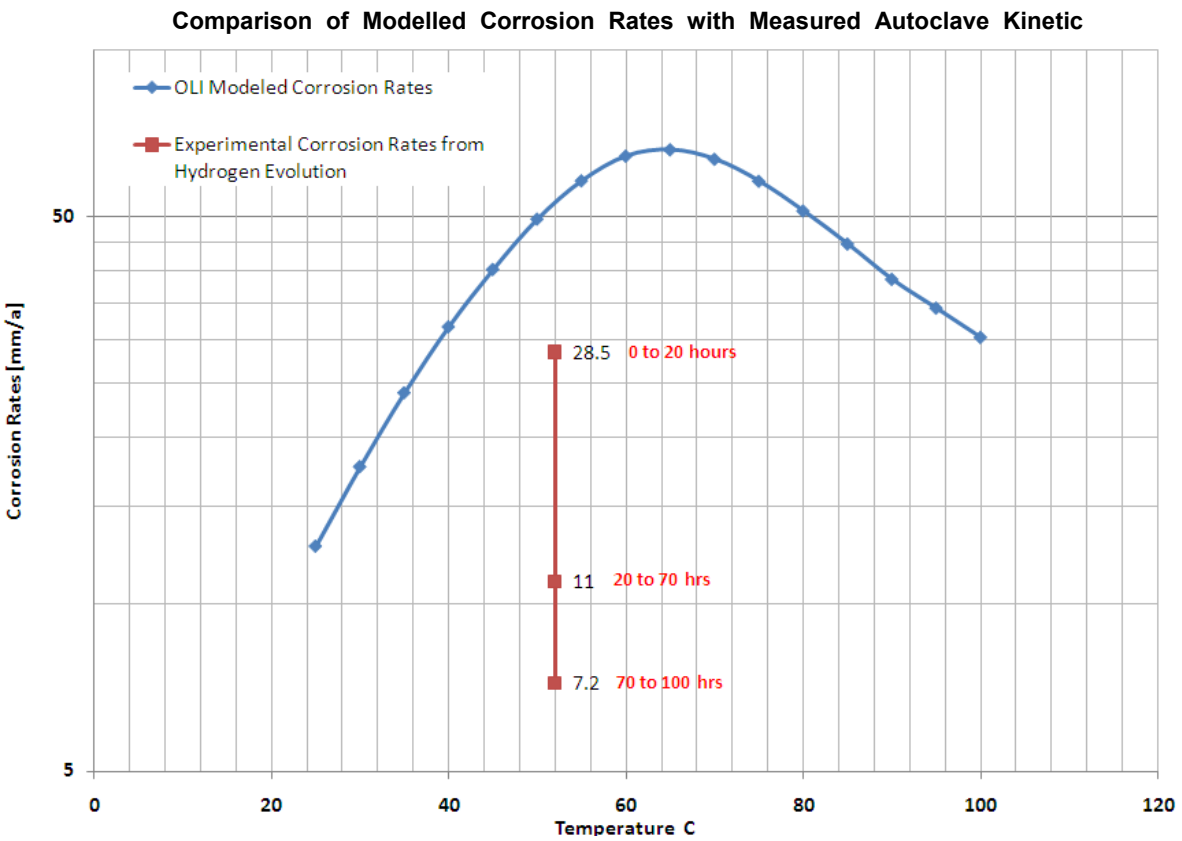


Figure 7-6: Comparison of Modelled Corrosion Rates with Measured Autoclave Kinetic Data

Although corrosion modelling has shown that carbon steel, in all likelihood, will perform adequately in a geothermal producing well; depending on the criticality of the wellhead equipment alternative metallurgy might be considered. The reason is that within wellheads high turbulence will exist under normal conditions of production which may remove the passivating layer and lead to flow induced localised corrosion, which is difficult to model, but has been observed in many detailed laboratory investigations within the temperature ranges of interest and in the surface piping adjacent the well head during the HPP trial (see **Figure 7-7**).

Figure 7-7: Evidence of flow induced localised corrosion in surface piping from the HPP trial

7.6.5 Trajectory

The recommended well design is a vertical well. This decision has been driven by the need to minimise well costs and to reduce technical challenges. Due to temperature limitations, MWD and steering equipment can only operate to approximately 3,000 m and they have not been reliable even to this depth. Deviated wells are unlikely to be possible with CT drilling. With 2-7/8 inch coil, high fatigue is already expected and deviating a well will increase the frequency of failure. Deviated wells will also increase drag, which has already been significant in trips through the Permian. All cost estimates assume a vertical well.

There are two key potential advantages of drilling deviated wells. Firstly, it would be possible to drill all the wells from a single pad location. This would make rig moves easier and less expensive, possibly even making it possible to simply slide the rig to another location. Secondly, it would make the surface transport piping simpler and less expensive as production brine could be gathered and re-injected at a single location rather than having to build pipelines long distances to individual well locations scattered across the field. The downside to drilling from a single pad is that the wells would have to be drilled with a portion of the well being deviated to reach the target location to intersect the fracture at the desired location. This could add at least $1.5-$2.0 million per well to at least four of the wells in the program. This additional cost would most likely not be offset by the benefits of drilling from a single pad. Therefore, wells will be drilled from individual pads. All wells will be vertical, which is the cheapest and least technically challenging method of drilling.

7.6.6 Drilling Fluid

Robust drilling fluid that is resistant to higher temperatures and contamination from H_2S, CO_2 and cuttings is critical in the successful drilling and completion of a well in the Cooper Basin. Significant time was lost managing the drilling fluid in all the past wells except for Habanero 4. The water based drilling fluid used for Habanero 4 is recommended for the top two hole sections. The drilling fluid for the final hole section has been simplified for use with CT to a weighted brine. This brine has less potential to damage the reservoir.

12-1/4 Inch Hole Section to 1,500 m

A simple water-based drilling fluid will be used to drill the 12-1/4 inch hole section. The fluid base is a non-weighted 5% KCl, PHPA, and Polymer system. This will need to be treated with lime, zinc oxide and biocide to manage the H_2S and CO_2. Mud density should be kept between 8.8 and 9.2 lb/gal but may need to be raised to 9.4 lb/gal prior to running casing due to tight hole previously experienced at 650 m to 850 m.

The challenges expected for the drilling fluid in this hole section include:

- Coal at +500 m which is likely to drop the pH,
- Screen-blinding when drilling through sand stringers,
- Bit balling, and
- Low levels of lost circulation around 1,000 m.

8-1/2 Inch Hole Section to 3,700 m

The lightweight drilling fluid from the 12-1/4 inch section will be used to start this hole. The density will be raised as depth increases to upwards of 15 lb/gal. The system will be gradually broken over to HPHT system by substitution of the organic polymers with more temperature stable synthetic co-polymers and dispersants (Driscal D, Polydril, Narlex). This change-over will commence at a depth of about 2,900 m and be completed by a depth of ~3,500 m. KCl can drop to 3% at this depth. A blend of Bentonite and Sepiolite will added for HT thermal stability. Sepeolite clay replaces part of the Bentonite that is normally used for a weighted mud system as this reduces potential gelation created by high temperatures and any influx of reactive gases.

Additional drilling fluid equipment required in this section includes mud-coolers and centrifuges. Geocoolers will be needed to keep mud temperature low enough for effective operations at surface. The centrifuges are essential in controlling mud properties, particularly the gel strengths. Not having the centrifuges would result in higher pump pressures, higher surge and swab pressures and poorly displaced mud in cement jobs. The shale shakers will also need to be fitted with high-temperature resistant screens.

The challenges expected for the drilling fluid in this hole section include:

- Rising gas content from coal-seams and low permeability sandstones.
- Evaporation leading to dehydration of the system.
- Driscal D additions cause temporary high-viscosity and gel strengths when being added at the hopper into the active fluid.
- Accumulation of ultra-fines from the turbine run could contribute to higher rheology and gel strength development.

6 inch Open Hole Section to +/- 4,200 m

This hole section is to drilled with clear 12.4 ppg brine to keep wellhead pressures below 2,000psi (13.8 MPa). Backpressure will be applied at surface to maintain the 8,400 psi (58 MPa) pressure required downhole to maintain wellbore stability. As a contingency the same HPHT drilling fluid system used in previous hole section could be used if coiled tubing drilling is unsuccessful.

Hole cleaning should be sufficient despite the low viscosity of the brine as the cuttings from the impreg bit /turbine combination will be very fine. An occasional gel sweep can be used to ensure complete hole cleaning if it is a concern during operations. The small size of the cuttings means they will need to be removed from the system with a centrifuge.

Having downhole rheological values and densities will be critical in successful drilling of the fracture. Thermal and pressure modelling can be provided for by SPT, now part of Schlumberger. Even with CT drilling, this will be critical for drilling through the main fracture without major losses and subsequent damage to permeability.

A contingent fracture sealing system is recommended. For Habanero 4, a set particle size distribution was developed with OPT using sized calcium carbonate materials to allow for the largest possible variability in the fracture width. The large particle sizes and high concentration of this system means that it may be operationally difficult to mix and pump into place. The solution applied at Habanero 4 to address this was to mix the system in slug pits.

7.7 Cement

The HGP wells require competent and continuous cement all the way to surface. This cement needs to be very ductile as it will be subjected to the same variation in loads as the casing is- it will be exposed to low temperatures and high pressures during the stimulation and to high temperatures during production. The required cement ductility can be obtained by adding 'well-life chemicals such as a liquid latex to improve mechanical properties of the set cement. The recommended cement should be tested and modelled with Well Life (FEA) analysis in detailed design phase. If the ductility is not acceptable, foamed cement can be used to improve the ductility.

It is recommended that both cement jobs are placed with the reverse cementing technique. This is the only method that ensures the cement sets at every depth and that there are no areas in the annulus that do not get displaced to cement. Reverse cementing with the stab in method can be used for the surface casing and a pump out float can be used for the production casing. The alternative cement placement techniques were eliminated as they jeopardise well integrity. It is not possible to get competent cement at surface with a conventional cement job due to the quantity of retarder that is required to allow the cement to circulate past the casing shoe. A conventional cement placement with a lower top of cement would allow the bulk of the cement to set but is not recommended as it is not possible to confirm that the cement sets at the cement-spacer interface and the resultant high pH environment may lead to caustic cracking. Two-stage cement jobs are not recommended as the stage tool is a weak point in the casing string and the area below the sliding sleeve may not be displaced to cement.

The high temperatures also create the potential for annular pressure build up. To prevent this, the drilling fluid needs to completely displaced and the cement slurry needs to have zero free water. The decrease in the hole size compared to the recent Cooper basin wells will assist with creating efficient displacement, however it is still important that the best practices for drilling fluid displacement are followed including:

- Condition drilling fluid prior to cementing.
- Ensure that progressive gel strength properties of the drilling fluid are maintained "flat" through good solids control, etc.
- Pump at highest rate safely possible. If batch mixing is required then portions of the mixed slurry should be pumped at maximum rate to aid in displacement followed by periods of slow pumping to allow for sufficient time to mix the next batch of cement.
- Centralise casing to at a minimum of 70% standoff if possible.
- Use spacer fluids with optimised viscosity to help ensure maximum mud displacement without intermixing of cement; i.e. higher then rheology of drilling fluid and less than that of cement.
- Minimise shut downs between conditioning of the drilling fluid and pumping the cement spacer and cement slurry as this allows the gel strengths of the drilling fluid to increase and effectively returns the wellbore to the same condition as it was in prior to circulation.

7.7.1 Drilling Bits

Significant focus on optimisation of drilling bits in recent GDY Cooper Basin wells has resulted in significant improvements in the drilling performance in the top hole sections and increased on-bottom time in the lower hole sections. In Habanero 4, the bit performance above the Roseneath Shale exceeded the performance in smaller offset bore holes (Beach wells and original GDY

wells). This is counter to the rule of thumb that drilling Rate of Penetration (ROP) increases when the hole size is reduced and indicates that the potential for improvement in Rate of Penetration in the upper hole sections is limited. Most of the drilling time in Cooper Basin wells is now spent in the Nappamerri, Patchawarra and Granite intervals; therefore focus should be placed on reducing costs or improving drilling performance in these areas.

The recommended strategy for optimising the granite section is to drill this section with a CT Drilling unit. Drilling performance is not expected to increase with this method, however the CT unit has significantly lower day rate and quicker trip times. The key risk of the coil tubing option is the ability to advance through the granite formations. A study commissioned on coil tubing drilling determined that coil would be able to withstand the loads applied drilling the Cooper Basin granite, but was unable to identify any examples of coil tubing drilling in granite. Before relying on this technology, it is recommended that existing ROP mechanisms for coil tubing drilling are tested in a shallow granite formation and, if required, at high temperatures in a laboratory. Technology development may be necessary for both the drive mechanism and the bit. Energy will need to be conveyed to the cutting structure either by turbines, motors (which are currently temperature limited but are being investigated by Baker Hughes) or a fluid hammer (which has a low tolerance for solids in the drilling fluid and unknown performance at high temperature). The most likely of these to be successful is the turbine as these units have successfully drilled on CT in the past and are of a metallic design with diamond bearings which has allowed them to operate at up to 230°C. Drill bit options include impreg bits, PDC, tricone or a percussive drilling head.

Table 7-6: Recommended Bit Strategy for HGP Wells

Bit #	Size	Type	In	Out	ROP (m/hr IADC)	ROP Range	Bit D.escription
1	12.25	Insert	0	750	12.3	20 to 25	Insert (415) plus motor for duracrust
2	12.25	PDC	750	1500	16.6	20 to 25	PDC - Aggressive 5-6 Bladed, 16-19 mm
3	8.5	PDC	1500	2200	7.1	5 to 10	Heavy Set 7-8 Blades, 13-16 mm, DOC Features
4	8.5	PDC	2200	3000	3.6	2 to 5	Heavy Set 7-8 Blades, 13-16 mm, DOC Features
5	8.5	PDC	3000	3300	2.3	2 to 5	Heavy Set 7-8 Blades, 13-16 mm, DOC Features
6	8.5	Impreg	3300	3700	1.2	1 to 2	Impreg- specified in conjunction with CSIRO
7	6	TBA	3700	4200	2	1 to 5	Coil Tubing- bit and drive mechanism TBA

If the challenges with the coil tubing well design are not surmountable, the back-up is drilling the section with a conventional rig. If it is necessary to revert to a conventional rig for the reservoir section The recommended bit strategy is to push the impreg bits as far possible and to revert to 5-6 series high temperature tricones when the rate of penetration dictates. The maximum improvement possible in ROP with a conventional drilling rig in the granite has been verbally estimated by suppliers and CSIRO as an increase of 2-3 times. An increase in ROP of 3 times for the last 500 m of the well would result in a reduction of drilling time of 21 days and an associated cost savings of $2.5 million from the $19.3 million/well in a 5 well campaign for the two string well design. An increase in ROP of this magnitude is not guaranteed and is unlikely to be achieved in the first wells of a program.

Further opportunity to optimise drilling in the Cooper Basin with a conventional drilling rig i.e., being more aggressive, would focus on the following areas;

- Investigate the potential for using the Kymera bit in the Lower Winton - Hutton Interval. This option has the potential to reduce the interval to a one bit strategy.
- Continue the development and testing of impreg bits (8 1/2 inch and 6 inch). This technology has the potential to both increase the ROP and to minimise the number of trips required to change the bit. In past wells, GDY has used Impreg bits in the lower most section of the Patchawarra and as far into granite as possible. Due to the long bit life of Impreg bits, extending the range of formations that can be drilled with an impreg bit would significantly reduce the total drilling time by reducing the number of trips required. Work commissioned from CSIRO in 2012 identified good material alternatives for drilling the Nappamerri with an impreg bit. Possible alternative materials for drilling the granite were also identified. Impreg bits are run on turbines which also improve reliability of the drill string due to the lower rotation, wear and vibration.
- Monitoring PDC improvement by other operators in the Basin.
- Optimisation of drill string and drilling parameters (Weight on Bit etc.) to minimise vibration and increase specific energy applied at the bit.

Under-balance drilling is another method of improving drilling performance that has been investigated. This technology is not recommended as the significant increase in spread rate associated with the technology is not justified by the limited success to date. Under-balance drilling (UBD) has previously been trialled on Savina 1 and Habanero 2. UBD was applied to the intermediate hole section of Savina 1 in an attempt to reduce well costs by increasing ROP. This cost benefit was not seen as the time saved by moderate improvement in ROP was offset by the time required to maintain and place a kill mud system. The granite section was not drilled in Savina as a prolific fracture was encountered at the base of the intermediate hole section and while controlling the well the drill pipe became irretrievably stuck. UBD was also a limited success at Habanero 2. The drilling performance was acceptable however it is suspected that the stuck pipe issues on this well were caused by wellbore collapse as sufficient back pressure was not held while making connections. Subsequent rock strength studies determined that for well bore stability it is necessary to maintain a minimum of 58 MPa. This will minimise wellbore collapse to ovalised breakout.

7.7.2 Drilling the Fracture

Drilling the main fracture is one of the most challenging aspects of the drilling operation. The primary plan is to drill this with a coiled tubing unit instead of a large drilling rig and use 12.4 ppg brine instead of weighted water-based drilling fluid. This should greatly simplify the fluid and pressure aspects of this part of the drilling operation. However, if for some reason it is not possible to drill the main fracture with CT conventional means would need to be used, namely weighted drilling fluid and a large rotary rig. Drilling within a very tight pressure window (See **Figure 7-8** below) with a weighted water-based drilling fluid caused multiple problems in previous wells. Special measures were taken to help ensure successful drilling of the main fracture. The density and rheological properties of the drilling fluid were measured at downhole temperature and pressure. This information was used along with SPT fluid modelling to help ensure that downhole pressure was maintained within the window while drilling the main fracture. In addition, a dynamic leak-off test was obtained by adjusting the pump rate after drilling through the main fracture. Similar modelling with SPT is recommended both if the main fracture is drilled with CT and if the fracture is drilled with conventional means of weighted drilling fluid and a drilling rig.

Even with CT drilling, if severe losses are encountered it may be necessary to temporarily seal off the fracture to minimize damage to permeable flow. In this case a system like sized calcium carbonate pill should be considered. The necessary testing was completed for Habanero 4 and is documented for the possible design of the LCM Pill. Additional focus on operational aspects of how this fluid pill would actually be mixed, pumped, and spotted into the fracture is recommended

While drilling in the reservoir rock, there is the possibility that more than one fracture may be encountered. If this is being drilled with CT with water as the drilling fluid then it would be possible to drill multiple fractures and no additional action would be required. With weighted brine and a CT unit, or a conventional set up, the contingencies discussed below are required.

- If a second fracture is encountered above the main fracture the contingency plan should be to seal it off with cement before attempting to drill further into the main fracture.
- If a second fracture is encountered below the main fracture while drilling with CT, the backpressure at surface should be reduced to allow reservoir fluid to enter the well to the depth of the original fracture. The coil can then be pulled out of the hole with the well being balanced on both fractures. The drilling fluid will not be able to be circulated; nor drilling continue; unless the surface equipment can hold 5,000 psi while pulling out.
- If a second fracture is encountered below the main fracture while drilling with a conventional rig and weighted mud, the drilling operation should cease and a dynamic pressure test conducted to determine if the fractures are able to hold the increased mud weight that is required to be placed to allow for expansion of the mud while the drill string is pulled out of the hole. If the modelling and dynamic pressure test indicate that this is not possible the LCM pill discussed above should be placed or the hole sanded back with calcium carbonate before the drill string is pulled out of the hole. It is unlikely with two fractures open that it will be possible to balance the fractures. This is because if the drilling fluid column is balanced on the upper fracture the well will be over-balanced at the second fractures and losses may occur if the fracture resistance is low. This is demonstrated in **Figure 7-8**.

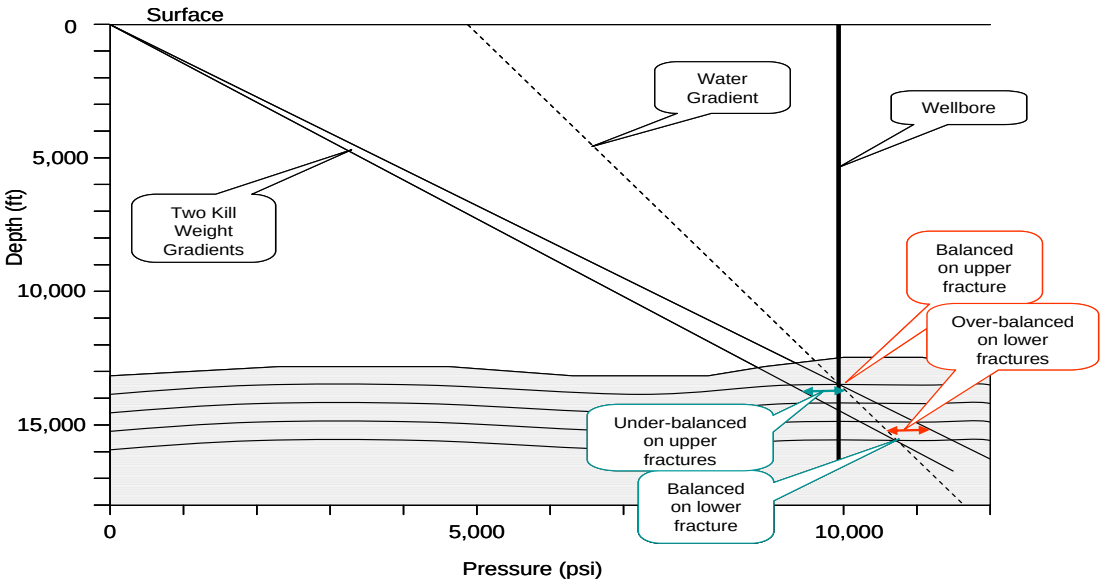


Figure 7-8: Pore Pressure and Fracture Pressure Estimates

The FDP wells are designed to intersect and produce from only one fracture. If wells in the future are intended to drill multiple fractures, it is recommended that CT drilling is combined with a concentric casing well design that would allow additional drilling fluid to be injected and thus increase the Equivalent circulating density of the fluid while maintaining a water gradient between the two fractures. This would require significant casing design work and a method to isolate the reservoir when tripping- this could be either a mechanical or a fluid barrier.

7.7.3 Completion Techniques and Equipment

The recommended well design is effectively a mono-bore well. Each of the two casing strings is capable of withstanding the hot shut-in and stimulation loads, which delivers on the requirement to provide two working stress designed barriers. This design does not provide a removable barrier;

however the corrosion in these wells has been analysed in detail and low corrosion rates are expected. Regular corrosion monitoring is recommended, and if corrosion is detected can either be slowed with chemical treatment or mechanical intervention installed.

If mechanical intervention is required it could be installation of either a casing patch or a completion. If a completion is required, Packers Plus has previously delivered packers that can operate at the high production temperatures and Welltec has qualified a Well Annular Barrier that can operate at both the stimulation temperatures/pressures and the production temperatures. A completion would require isolation of the reservoir with two barriers. To prevent damage to the fracture, it is recommended that the well is not killed with drilling fluid, but rather that mechanical barriers are placed with either Coil Tubing Unit (CTU) set bridge plugs or balanced cement plugs. These would need to be drilled out through the installed completion or casing patch and would remain as short restrictions to flow.

7.8 Drilling Operations

7.8.1 Drilling Lease

Each well will require a separate lease of approximately 150 x 100 m with either an adjacent turning bay or drive-through ability with two good accesses for delivery of drilling materials and the rig. Preplanning of lease orientation with Surface engineering is important to minimise pipelines and to ensure that appropriate areas remain after surface facilities are installed to enable drilling equipment to be rigged up for later interventions.

- The lease area will need to be prepped with:
  - Cellar preset
  - Conductor preset deeper than expected duracrust
  - Drilling sump and turkeys nest

7.8.2 Minimum Rig Type

It is recommended that the future Habanero wells be drilled with two rigs. A conventional drilling rig should be used to drill and set 7 inch casing to 3,700 m. A coil tubing unit should be used to drill the final 500 m.

Conventional Rig

It is strongly recommended that a rig that has been operating within Australia (a hot rig) is selected for drilling operations. There are currently several rigs operating in Australia that could be upgraded to meet the minimum requirements below. Picking one of these rigs up following on from their current drilling brings several benefits including that the rig has been in an operational condition for over 12 months, and experienced crews that have been working continuously together during this period. The time-depth curves assume that rig operations commence at a level of efficiency equal to the best past performance and that there is no significant down time for rig breakdown.

The minimum rig specification is based on drilling the 2-String well design option as the 7 inch string in this design is the largest load envisaged.

- Horse power - 1,500
- Hook load - 750,000 lb (sufficient for 7 inch casing load to 4,100 m of 425,000 lb, 80,000 lb blocks and top drive allowance and drag up to 50,000lb which was experienced while running casing on Habanero 4)
- Substructure - 30 ft clear height

- Top Drive - 500 Ton
- Iron Roughneck - Full torque capability for make and break of drill string components
- Catwalk - Automated pipe handling
- Pumps - 3 x 1,400 horse power with 10 inch stroke and 7,500 psi discharge, high temperature elastomers
- Stand pipe - 5 inch 7500 psi
- BOPE - 13-5/8 inch 10k with high temperature elastomers
- Choke Manifold - 3-1/16 inch 10K with remote and manual chokes
- Tanks - 1,500 bbl active system, 1,500 bbl reserve tank system with mix-ability to service both systems
- Mud Coolers - 2 x 800 GPM coolers
- Monitoring - PVT on all tanks and PVT, flow, temperature system with recording capabilities on active system

Coil Tubing Rig

A CT rig with Managed Pressure Drilling (MPD) equipment is recommended for drilling the reservoir section. The CT drilling is to commence at 3,700 m and continue to Total Depth (TD). This section contains the Merimellia, Tirrawarra and the granite basement formations. CT is primarily recommended as formation damage to the fracture can be minimised by drilling with a compatible brine. The CT option also represents a significant cost savings over drilling this section with a conventional drilling rig and when combined with the MPD equipment allows quick tripping with pressure held at surface.

The primary concern with CT drilling is the performance of the turbine or high temperature motor in the granite. Turbine drilling with an impreg bit was trialled in the granite at Habanero 4. The turbine performed well and the impreg bit performance was moderate. The bit was pulled, due to a drop in ROP, after drilling 190 m (the Merimellia and 45 m of basement) at 1m/hr. CSIRO has since conducted laboratory tests on improving impreg performance in the Cooper Basin and has offered several material suggestions to Smith bits to optimise the bits. A trial of a high temperate mud motor or turbine and diamond impregnated bit is recommended, prior to finalising the drilling program, to establish if the Rate of Penetration is adequate.

Current assumptions are that the CT drilling will need to be conducted with 12.4 ppg brine. This is a requirement as a 2,000 psi surface pressure limitation for coiled tubing has been set. If this limitation can be addressed, operations can move towards CT drilling with water which would allow drilling multiple fractures. The 2,000 psi surface pressure limit for the CT system is based on:

- Reduced collapse resistance of the coil at high temperatures.
- Lower yield strength CT due to potential CO_2 and H_2S.
- Operability of the stripper rubber on the coiled tubing.

The CT drilling equipment specifications include:

- 10,000 psi circulating system (refer to **Figure 7-9**)
- High Temperature Coiled tubing connector(s)
- HPHT Dual check valve
- HPHT Pressure actuated circulating tool
- HPHT disconnects

- HT mud motor or turbine
- Diamond impregnated bit optimised for Cooper Basin formations
- Two 2-7/8 inch 80,000 ksi coil tubing strings- one analysed option is presented in **Figure 7-9**. Two strings are recommended as CT Drilling is often regarded as unreliable and this seems to be a result of high fatigue related failures of the coil. The likelihood of fatigue related failures increases with the diameter of the coil.

Table 7-7: 2-7/8 inch 80,000 psi CT string Design Option

		MD (ft) =	18,040	Wall Area	Weight	Volume		Weight	Weight
Wall (in)	Length (ft)	Bottom (ft)	Top (ft)	(in^2)	(lbs)	(gal)	(bbls)	(lbs)	(lbs)
0.224	1,125	507	-618	1.866	7,136	270	6.4	3,055	10,191
0.203	1,620	2,127	507	1.704	9,386	403	9.6	4,553	13,939
0.188	1,709	3,836	2,127	1.587	9,221	435	10.4	4,921	14,142
0.175	14,204	18,040	3,836	1.484	71,687	3,695	88.0	41,751	113,439
	18,658				97,430	4,804	114.4	54,280	151,710

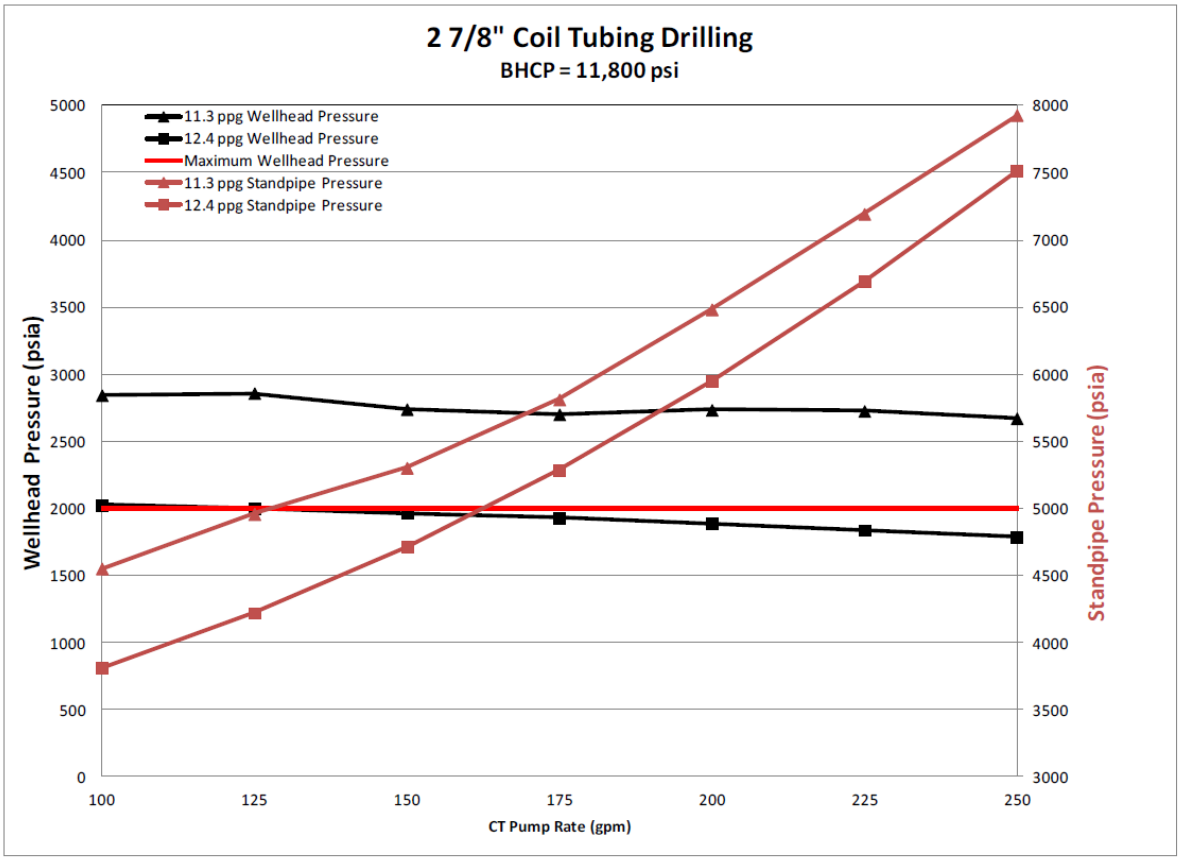


Figure 11 2 7/8" Coil Tubing Pressures vs Pump Rate

Figure 7-9: Coil Tubing pressures vs Pump Rate

7.9 Opportunities for Cost Improvement

7.9.1 Operational Changes

Opportunities for improving (decreasing) the cost of the recommended 2-String design wells through changes to drilling operations include the following technologies and methods:

- Compact Wellhead
- Improved Drill Bit Design- Increasing ROP by 3 times in the lower 500 m of the well has the potential to reduce drilling time by 21 days and reduce average well costs by $2.5 million. This technique is an alternative to the CT option and is not an additional savings on the presented costs.
- Improved drilling efficiency through the "Drill the Limit" methodology

This is a misconception that eliminating the reverse cement job would also decrease costs, however the reverse cementing is essentially cost neutral compared to conventional cement placement. There is a slight increase in the cement volume and some more equipment is needed for the jobs. This is offset by a reduction in cost of the materials as less retarder is needed for the cement slurry. On a whole of life basis, reverse cementing is clearly the most cost effective option as it reduces the risk of incomplete cement fill in the annulus which was the root cause of the failure in Habanero 3.

Multiple Rig Campaign

Another potential means considered for reducing rig cost was the use of multiple rigs. The idea is that a smaller, lower cost rig could be used for various portions of the well. It was determined that the difference in the rig day rate cost was only about $15,000 per day. This savings is almost immediately eroded with conventional rigs as using multiple rigs would require additional rig moves. Under these conditions one would have to drill with the cheaper rig for a large portion of the well just to break even in cost. Therefore, the use of multiple rigs is not a cost effective idea.

It is cost effective to have a small mineral rig to drill the first 100 m of a well through the duracrust. This is more of a risk mitigation strategy than a cost reduction. If duracrust is encountered, a low cost mineral style rig could slowly grind through and run casing rather than having a large, expensive rig spend additional days drilling through the duracrust.

7.9.2 Opportunities for Increasing Thermal Power

There are a number of means to increase thermal power both by increased flow from or injection into a given well or increased temperature from a given well. They include the following.

Insulated Tubing

One method that could be implemented to potentially increase production temperature is the placement of nitrogen between the production / rate string above the production liner (See **Table 7-2**, 3-String w/Insulation). Recent flow test data showed that the with the fracture producing 236°C fluid at depth the surface production temperature was 215°C with the well flowing at 16 kg/s. That is a loss of 21°C. Modelling indicates that this temperature loss could be reduced if production rate is increased, but still some temperature loss will occur. To reduce this loss and increase production temperature, and associated power production, some type of insulation may prove cost effective. A nitrogen cap placed between the 7 inch production tubing and 9-7/8 inch production casing was tried on Habanero 4. Results of that field test were minimal improvement in temperature at best. Additional work may be done on the potential use of nitrogen to further improve and/or better understand this method of insulation.

Another way to insulate the production tubing and improve the production brine temperature is to use actual insulated tubing. This could be used in the Design Option that 3 strings of casing with the last string being a liner with a rate string hung above that (See **Table 7-2**, 3-String w/Insulation). Modelling would need to be done to determine the potential benefit that could be realised in increased production brine temperature.

Finally, the well could be insulated further through the use of foam cement on one or more casing strings. Test data exists that shows that the incorporation of a gas phase in cement can lower the thermal conductivity of cement.

Multilaterals

Another means of potentially improving production is to drill multi-lateral holes into the main fracture. This would most likely be done with the use of CTU using the technology from Tempress or something similar. This technology would include a Hydraulic Kick-Off (HKO) tool and a Jet TurboDrill (JTD).

Flowing from two or more laterals into a parent wellbore could reduce the near wellbore pressure drop that occurs at the fracture near the wellbore due to the high velocities.

Deflagration

A potential means of increasing production from a given well is the use of deflagration technology. This is the use of a controlled explosion that creates a pressure wave that can fracture the rock in the area surrounding the immediate wellbore. This technology has not been used in a Habanero well but has been claimed to improve flow from both oil and gas wells and geothermal wells in other areas of the world. The vendor that has been investigated that has a system that can be used at temperatures encountered in Habanero wells is Precise Stimulation.

Diverter Stimulation

Diverter Stimulation technology has been used in several wells in the USA. This technology has been developed by AltaRock Energy. It's primary focus has been to stimulate multiple fractures in a given wellbore by providing a means of sealing one fracture so that pressure within the wellbore can be increased and fluid injection can occur in and additional fracture or fractures. Although only one fracture has been stimulated in the Habanero area, the extremely high rates at which these stimulations were conducted means that the well bores have already been exposed to the maximum pressures they are designed to contain (10,000psi at surface). The increase in pressure that the AltaRock technology is thus limited as the surface pressures cannot be increased and it is only the loss of pressure due to friction in 7" casing that can be regained. It is considered unlikely that this small increase in downhole would have any benefit.

7.10 Reservoir Logging and Testing

The following logs are required for HGP development wells:

- Calliper prior to cementing to estimate cement volumes and other modelling
- Kinley Calliper log should be run to monitor corrosion on production tubing.
- Spectral Gamma Ray log should be run for DMITRE.

Table 7-8: Logging requirements for HGP wells

Hole Section	Intermediate Casing(s)	Production Casing	Open Hole
Spectral Gamma Ray (Open Hole)	Yes ($100K)	Yes	Yes
Calliper Log (Open Hole)	Yes	Yes	Yes
Cement Bond Log	No	Yes	N/A
Kinley casing Calliper Log ($200K)	No	Yes ($200K)	N/A
LWD Resistivity Image	No	No	Yes

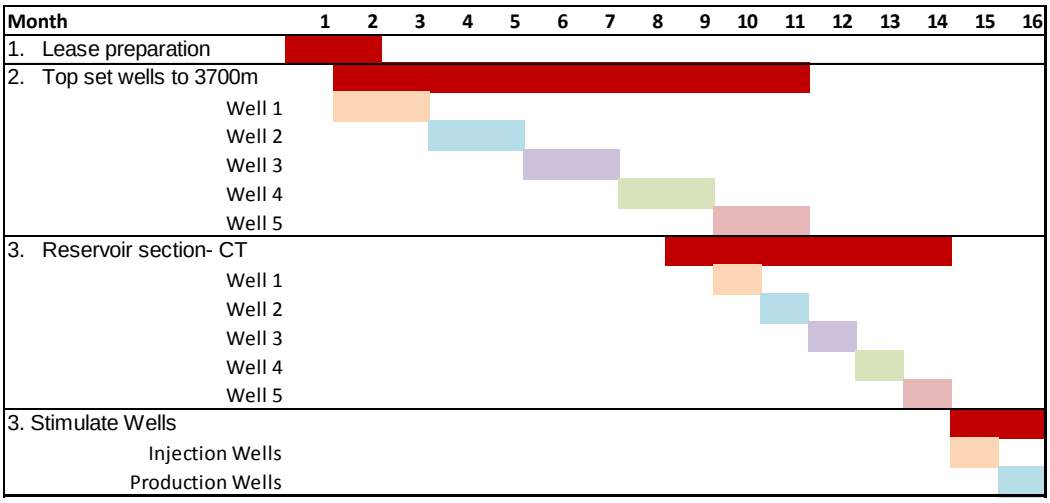
Ideally, at least one good image of the open hole main fracture should be obtained during this campaign. A possible candidate system for this is the resistivity log in the Baker "Startrek" Logging-While-Drilling (LWD) logging system, which is currently rated for 165°C operation temperature. Circulation temperature in the open hole granite section where this log is needed should remain well below 165°C during circulation based on temperature modelling done for Habanero 4. Additional modelling would need to be done to ensure that this will still be the case in this smaller hole size geometry. In addition, risks would need to be thoroughly evaluated before a final decision was made to attempt to log the open hole section with LWD. Unfortunately, since LWD cannot be run with coiled tubing, the granite open hole section would need to be drilled with conventional drilling rig and weighted mud drilling fluid. This would mean additional cost of around $2.8 million for the well. In addition, there would be increased risk of permanently damaging the main productive fracture if whole drilling fluid is lost to the formation during the drilling and/or completion of the well.

7.11 Drilling Execution

7.11.1 Sequence and Timeframe

The drilling program for Habanero field development will require four phases:

- Lease preparation, including
  - Conductor installed to below expected duracrust
  - Cellar installed
- Top set wells- Conventional drilling rig set 7 inch casing to 3,700 m
- Reservoir section- CTU to drill from the 7 inch casing shoe to the fracture
- Stimulate Wells- 1 week for production wells and 2 weeks for injection wells



7.11.2 Drilling Duration

The average well with two casing strings in a 5 well campaign will require 57 days with a conventional rig and 15 days with a CT rig.

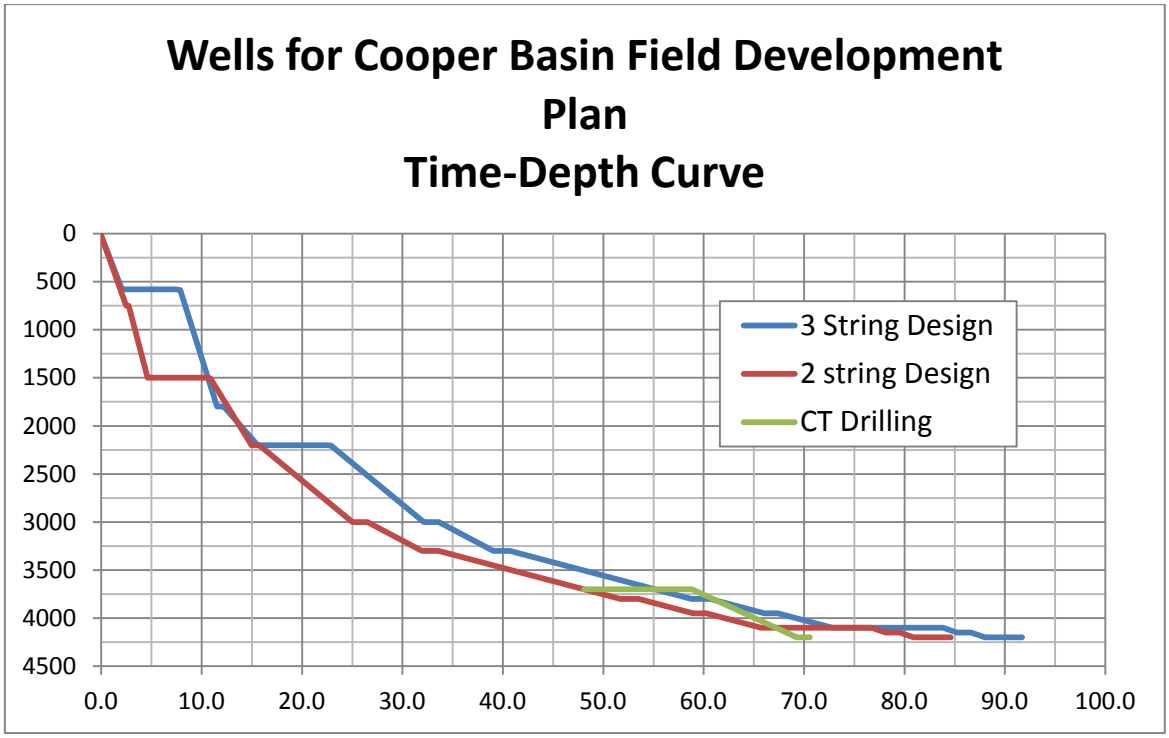


Figure 7-10: Time-Depth Curve for HGP Well Options

This time-depth estimate has been based on rates of penetration achieved on past Habanero wells and reasonable estimates of operational activity for the non-drilling times (the flat times). The bench marks set by prior performance in the Cooper Basin wells for the flat times are not directly applicable to the FDP wells as downsizing the wells decreases the size of all equipment at surface and should improve times significantly. As seen in **Figure 7-10**, the combination of this process and eliminating a casing string results in time-depth curves that have aggressive seeming improvements.

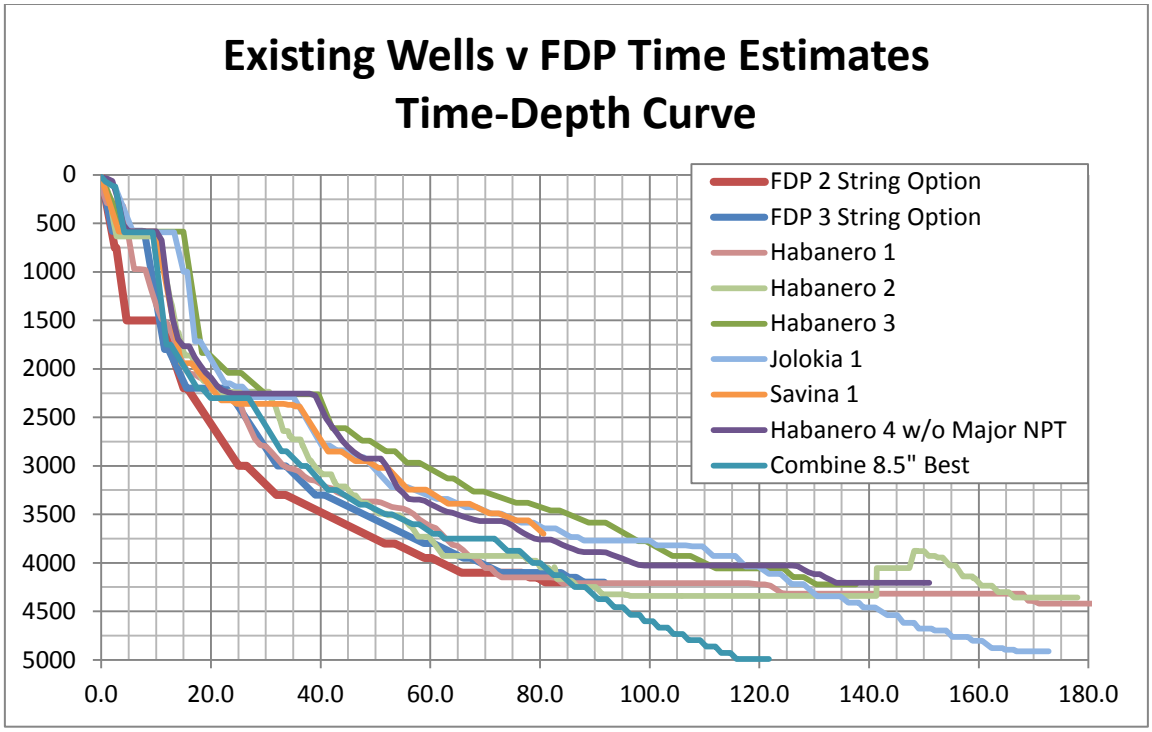


Figure 7-11: Time-Depth Curve comparison of HGP Well Designs VS Previous Cooper Basin Wells

A comparison to the past slim wells only (Habanero 1 and 2) provides a less extreme comparison and demonstrates that the predictions are reasonable as significant improvement in top hole drilling rates can be expected with the bit improvements GDY has managed over the last 10 years.

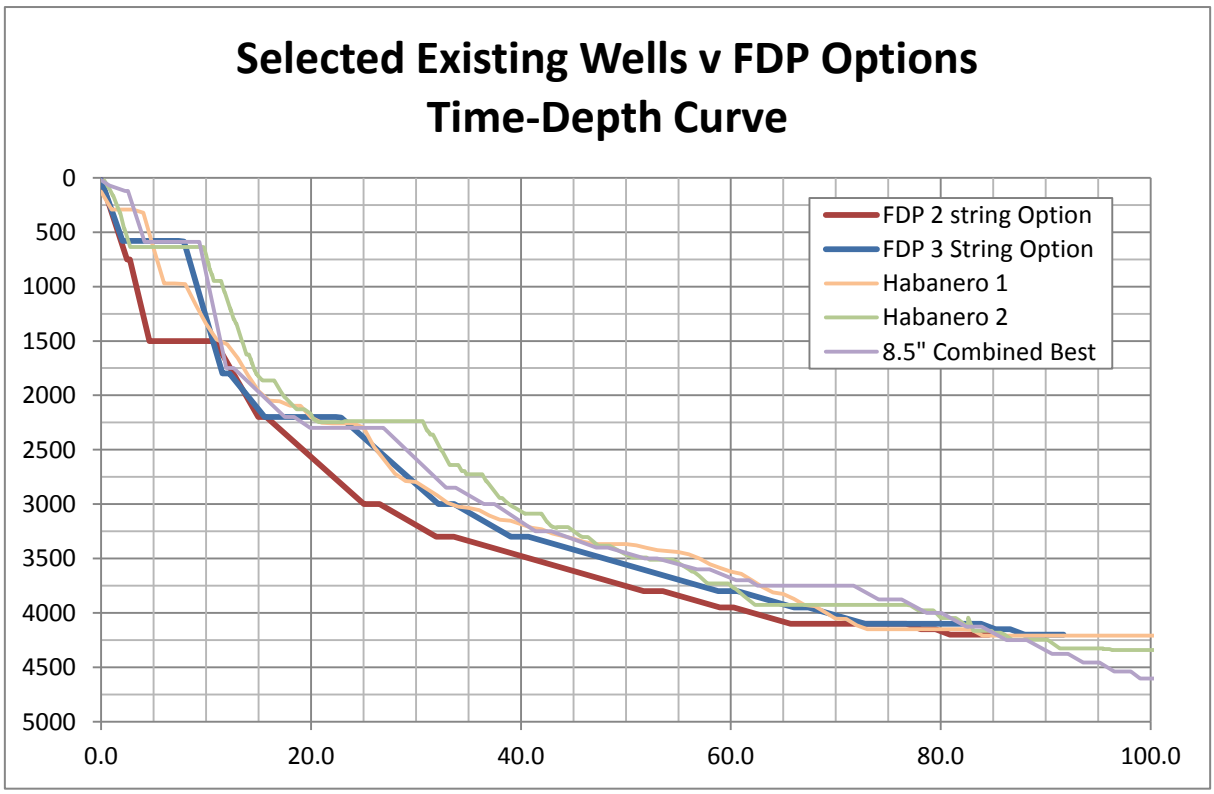


Figure 7-12: Time-Depth Curve comparison of HGP Well Designs VS Slim Wells

7.11.3 Drill the Limit

Drill the Limit methodology is a technique applied to sequentially decrease the time undertaken for drilling operations. The benchmarks and time savings predicted in previous Drill the Limit studies on Rig 100 cannot be directly translated to the FDP rig campaign as the rig size is different. Instead a generic repetitive task efficiency improvement curve was used. Campaign costs were assessed with the two levels of efficiency presented in **Table 7-9** below. The low efficiency improvement curve has been applied to the costs presented in **Table 7-17**.

Table 7-9: Repetitive Task Improvement Estimates

Well	1	2	3	4	5	Comment
High Efficiency	100%	90%	79%	74%	70%	H5 regarded as the '1st' well
Low Efficiency	100%	94%	90%	86%	83%	H5 regarded as the '5th' well

These assumptions were applied to all time based costs (drilling and flat time). The savings predicted through application of the low efficiency improvement curve and potential improvement in ROP are presented in **Table 7-10**.

Table 7-10: Drill Time of HGP Well Designs VS Improved ROP & DTL Wells

	Total Days	Rig Days	CTU Days	Rig Days saved
CTU	70.6	56.1	14.5	28.5
2-String	84.6	84.6		
3-String	91.7	91.7		
ROP	63.6	63.6		21.0
DTL	71.9	71.9		12.7

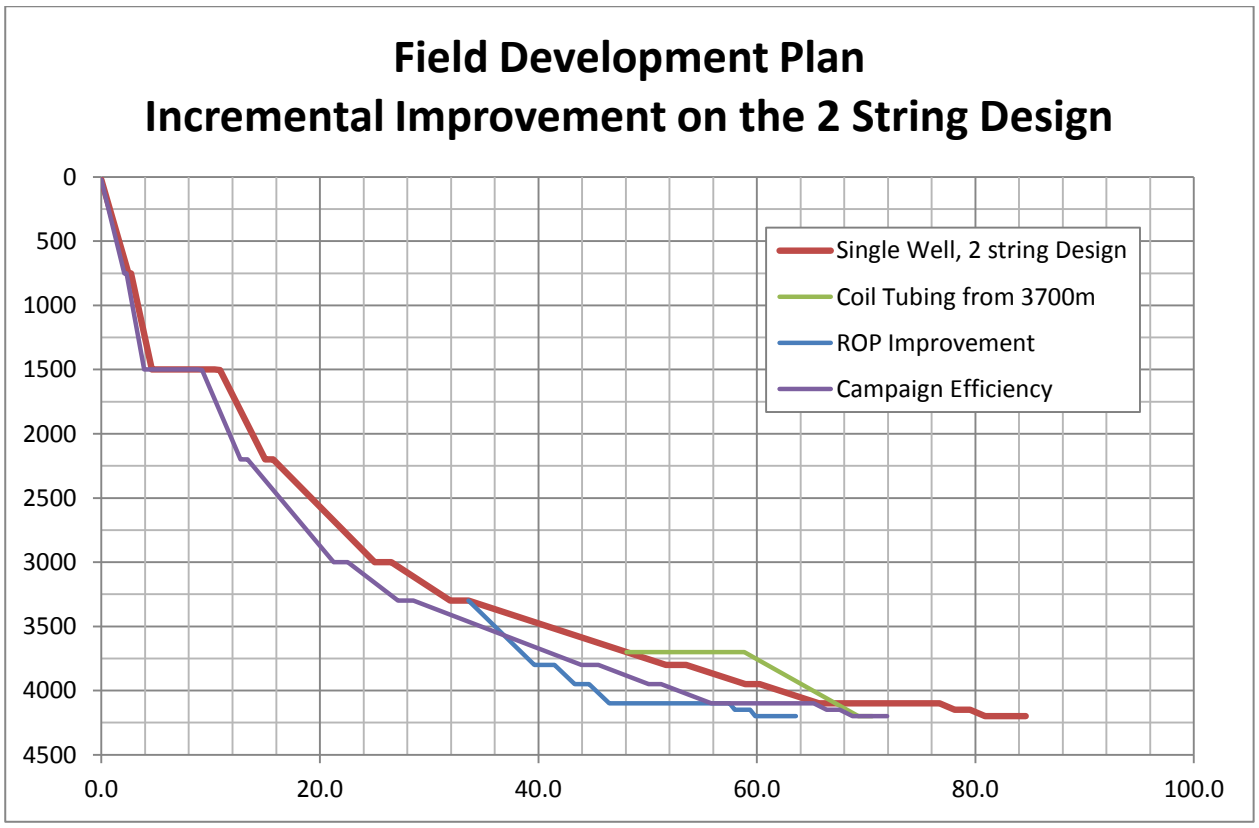


Figure 7-13: Time Depth Curve for HGP Well Designs

7.12 Operations and Maintenance

Operating Philosophy

- Wells will be suspended with the 12.4 ppg drilling brine in the well. This will result in a 2,000 psi pressure at surface which will be sufficient to drive free flow. If required CTU can be used to Kick Start the well by displacing to lighter fluids.
- Continuous well warming or well bleed when wells are on standby is not mandated.
- A well warming process achieved with a slow increase in production rate is recommended when production wells commence flow (when moving from 'cold' condition to 'hot' condition)
- Instrumentation philosophy is continuous monitoring of pressures in each annulus and P&T in tubing (production and injection).
- No active annular pressure management is envisaged
  - If a second barrier is put in place with a packer and completion string; annulus management should include some amount of nitrogen to absorb the changes in fluid volume due to changes in well operation temperature rather than allowing the trapped liquid volume to increase in pressure. The nitrogen volume could be minimal to just provide pressure management or it could be increased to provide some additional benefits such as insulation and/or corrosion protection
- Avoid leaving plugs down the well on completing well or on suspension
- Regular monitoring of corrosion is required. This can be achieved with surface coupons and scheduled calliper logging.

7.13 Past Drilling Costs

The past well costs for Cooper Basin have varied significantly but do approximately follow the Grubb curve expected for new technology. Habanero 1 was drilled as a slim well that could be used as an injector only and used the same assumptions as surrounding petroleum wells. Habanero 2 costs increased as multiple sidetracks were required. Habanero 3 was a large bore well. It was operationally successful and was drilled with few large scale incidents but subsequent well failure indicated design issues. Subsequent wells were all large bore and the cost increases reflect a spike in steel and personnel prices in 2006. Habanero 4 was the first well to address the failure mechanisms of Habanero 3 and as such carries significant engineering costs. From a well integrity point of view it has been 'gold plated' and as such is expected to be the 'highest unit cost' well. The recommended FDP wells are expected to be significantly cheaper as they are slim bore wells and it is assumed the learnings from Habanero 4 are successfully applied and that continued savings are possible with campaign drilling.

Table 7-11: Comparison of costs with past Cooper Basin Wells

Well	Spud	Rig release	Days	Rig	Cost	Well Design	Total Depth
Habanero 1	15/2/2003	14/10/2003	241	Century 27	$11,400,728	6”	4,421 m
Habanero 2	10/07/2004	3/01/2005	177	Century 27	$25,718,307	8.5”	4,200 m
Habanero 3	15/8/2007	5/02/2008	174	Rig 100	$25,718,307	8.5”	4,200 m
Jolokia 1	13/3/2008	21/09/2008	192	Rig 100	$35,053,626 (drill only)	8.5”	4,911 m
Savina 1	March 2009 Savina 1 secured with a cement plug at 2,640 m after a program of actions to recover stuck drill pipe was unsuccessful.						
Habanero 4	9/3/2012	8/09/2012	183	Rig 100	$50,852,947	8.5”	4,204 m

7.14 FDP Drilling Cost Estimates

The table below demonstrates the range of costs possible with the 4 well designs considered in this stage. The recommended well design is expected to average $16.5 million per well (if part of a 5 well campaign) with the assumptions of the final line in **Table 7-12**. This is the cost that has been used in the cost calculations and is recommended as:

a) The included Non Productive Time is in line with past experience in the Habanero field, and

b) The low efficiency learning curve is more likely to be obtained than the high efficiency curve as many of the savings normally obtained in a drilling campaign (casing seat change, bit selection etc.) have already been achieved with existing wells.

Table 7-12: Production Well Cost Estimates (Australian Dollars)

Option	3-String	3-String - Insulation	2-String	2-String w/ CT
Average Single Well Cost	25.6	25.7	23.5	21.1
Average Single Well Cost with 25% NPT	28.2	28.3	25.9	22.7
Average Campaign* Well Cost	18.3	18.2	16.5	14.0
Average Campaign Well Cost with Low Learning Efficiency	19.1	19.1	17.3	14.8
Average Campaign Well Cost w/25% NPT	20.4	20.3	18.5	15.7
Average Campaign Well Cost with Low Learning Efficiency and 25% NPT	21.4	21.4	19.3	16.5

Key assumptions in the well costs presented above are:

- No contingency on tangible items or service costs (other than time allowance above)
- 750k rated rig- Day rate of $50,000; MOB/DMOB cost of $4 million, inter-well rig moves in 10 days with $300,000 trucking
- Campaign includes 5 wells. Campaign cost improvements were driven by
  - Bulk purchase discounts of 15% on tangible items
  - Time improvements calculated on a generic "Repetitive Task Improvement Curve" assumptions
- All technical assumptions are confirmed in detailed design with no increase in well cost
- Singe well unit costs were assumed to be consistent with Habanero 4 costs (2012). Adjustments were made based on :
  - Planned future reduction in services
  - Downsized well equipment - casing, wellhead, bits & ROP, cement volumes etc
  - Services were rounded to a day-rate and applied to the new time estimate
- Key learnings are successfully applied to future wells.

7.15 Summary and Further Work

The recommended well design is a slim bore well (6 inch at TD) with 2 casing strings and uses a CTU to drill the reservoir section. The average cost estimate in a 5 well campaign for this well design is $16.5 million/well.

A trial of a high temperate mud motor or turbine and diamond impregnated bit on coil is recommended, prior to finalising the drilling program, to establish if the ROP is adequate. If ROP is not adequate, the back up well design presented (the 2-String option) results in an average cost estimate of $19.4 million/well in a 5 well campaign.

Detailed design needed prior to commencement of work would take 18-24 months. Detailed Well design and construction should be done according to the GDY's "Well Engineering Management System Description and Processes" (WEMS) and GDY's "Drilling and Completions Technical Standards Manual". This work will need to include confirmation of acceptability of well design with all stakeholders.

Aspects of the well design that need to be addressed in detailed design include:

- A regional formation strength study to increase confidence that acceptable casing shoe tests can be achieved at the nominated casing setting depths.
- Confirming that the Double barrier policy can be satisfied through fixed (cemented) barriers only- no removable barrier.
- Modelling of the reverse cementing jobs to confirm displacement issues from the past well are addressable by reducing the well size (increasing annular velocity) and increasing fluid viscosities.
- Demonstrating the ability to penetrate granite on coil tubing by a trial of the impreg and turbine in granite. ROP impreg optimisation is a major technology challenge that can provide significant value with both of the discussed well designs.
- Selecting of casing point for 7 inch casing before drilling open hole with CT.
- Confirming that the corrosion allowance is satisfactory.
- NACE Fit-for-Purpose testing of the 125 ksi casing material.

8. POWER GENERATION FACILITIES

8.1 Introduction

This section draws on the information discussed in the reservoir and drilling sections to conceptually design and cost production facilities for a commercial EGS project at the proven Habanero EGS resource. GDY's Surface Engineering team investigated small EGS projects supplying electricity and/or heat to a local load. The following concepts were investigated:

- Two, four and six well power generation projects,
- maximising the reuse of existing equipment,
- direct heat projects, and
- an ongoing research and development trial using the existing doublet (Habanero 4 and Habanero 1 wells).

A six-well, nominal 7.5 MW_e project was considered the *'base case'*, and most efforts were concentrated on this option. Alternate development concepts were developed and investigated to a lower level of detail.

Efficiency of CAPEX assumed the highest importance and studies were undertaken in the second half of 2013 to explore the limits of design innovation. These efforts focused on the following areas:

- Packaged power plant design
- Balance of plant within plant boundary
- Heat exchanger design and manufacturing costs
- Brine field piping

In parallel with this, prospective Cooper Basin markets were engaged, and conceptual designs targeted to these markets. In particular, the opportunity to supply process heat, rather than electricity, was identified and optimised for the requirements of typical Cooper Basin natural gas treatment plants.

8.2 Background information

8.2.1 EGS Power Plants in the Cooper Basin

There are many differences between an EGS project and a conventional geothermal project as well as some factors arising from the Cooper Basin location. These are discussed in this section.

As shown in **Figure 8-1**, there is an obvious similarity with a conventional geothermal project that is developed using a binary organic rankine plant, with the key difference that the brine is produced at very high pressures (360 barg) and must be reinjected at even higher pressures (450 barg). A direct flash plant could not be employed because the parasitic power required to reinject the brine from near-atmospheric conditions would be prohibitive. The Habanero brine also contains antimony; calcium and carbon dioxide, which lead to calcium carbonate deposition; and silica, all which could be problematic in a direct flash plant, where geofluid steam is admitted directly to the turbine.

The high brine pressure creates challenges in designing and procuring equipment, and significantly adds to project capital costs. The pressure drives up heat exchanger costs, which constitute approximately 25% of the total cost of plant, making them a key area to explore innovation. Also, the reinjection pump and seal technology is on the edge of technically proven limits, meaning that this equipment has a high cost and uncertain reliability. In addition, the wall thickness required for brine piping causes high material costs, high construction costs, and the need for excellent quality assurance. Furthermore, valves can cost up to an order of magnitude higher than equivalent sized valves in low pressure systems.

The Cooper Basin environment is remote, requiring all plant to be road transportable, and construction costs are high. The aridity of the area means that cooling water is scarce, driving the design towards "dry-cooling". High summer-time temperatures (up to 50°C) require large investments in air cooler surface area. The environment is very dusty, prone to insect plagues after rain, and the roads are rough, meaning that failure to properly package equipment can result in its destruction before reaching the site.

As proven by the HPP Project, however, these issues are all technically surmountable and the challenge is to achieve it at low cost.

Once energy has been extracted from the brine in the exchangers, there are numerous options for the power plant cycle to convert it to electricity. A brine temperature of 220°C means that a water flash plant can be efficiently used, however ORC cycles using hydrocarbon fluids and refrigerants are also competitive.

Turbine designs vary from geared steam turbines similar to that used in HPP to low-speed axial and radial turbo-expanders. This study has revealed that for the small project sizes (7.5 MW_e), suppliers prefer to offer simple turbine designs, often with fixed inlet geometry. This means that off-design efficiency can suffer and the consequences of actual brine conditions not matching the design (either too much enthalpy or not enough) can be severe.

This is one of the areas in which a small Habanero project suffers from the lack of 'economy of scale'. Specific CAPEX ($/MW) could be expected to decrease if the projects under consideration were of 25 MW_e or greater capacity.

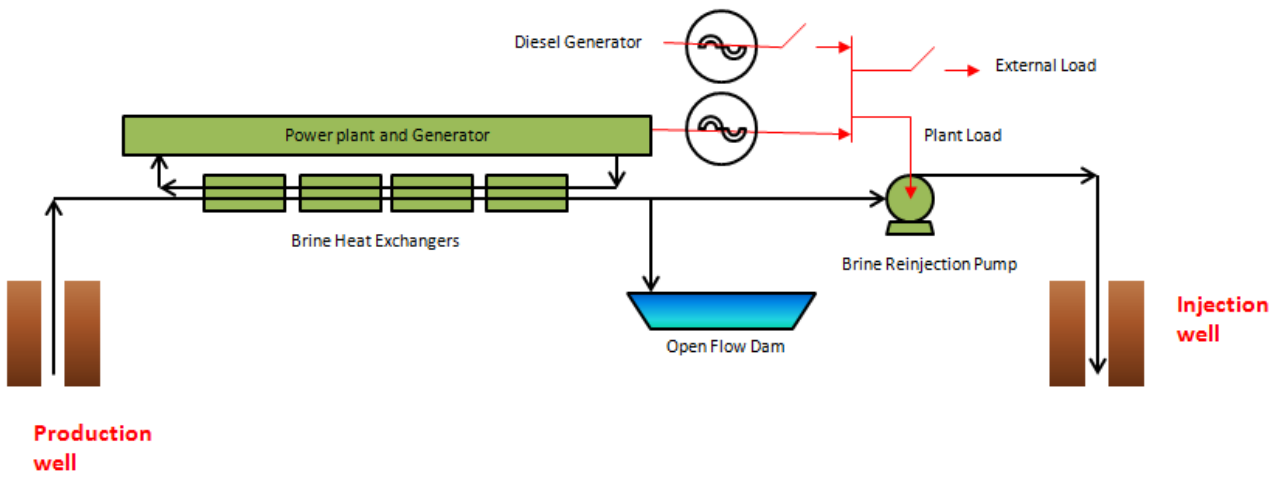


Figure 8-1: A Cooper Basin EGS Binary Power Plant

8.2.2 The Importance of Availability

Availability is critical in remote power generation projects where the customer is producing a product for sale such as a gas or mining project. Availabilities of greater than 99% are common. Because of its criticality, availability is discussed in a separate section here rather than just stated as an assumption.

Incumbent gas producers have an extremely high expectation of power/heat reliability/availability for central gas plants. For example, Moomba operates with 8 MW_e of generating equipment, ~4 MW_e of spinning reserve, and an N+1 philosophy. N+1 simply means that enough spinning reserve is required to cover the loss of the single largest generator. For this reason, Moomba tends to have more small generators rather than less larger generators. However, it is likely that satellite stations have lower availability and reliability requirements.

This means that a remote geothermal generator would need to have very high availability and reliability, and that the gas producer will need to have spinning reserve equivalent to the power provided by the geothermal generator. Consequently, the gas producer will likely be in an undesirable situation of needing to operate 100% spinning reserve. As a result, a satellite station may be a more suitable load for a next EGS based plant, but these typically have lower loads, in the order of ~1 MW_e.

Like any facility, EGS power plants can improve their availability by layering redundant equipment into the plant, however this comes at great cost. Further, availability cannot be improved beyond the level set by the power line. Power line availability in this region is governed in the first instance by the impact of electrical storms and dust build-up. With a reasonable level of investment in surge diversion, the advice from Cowell Electrical from operating a number of power lines in this part of Australia is that availability is 96-98% (difficult to obtain real operating data to be more precise). This could be improved slightly by running an earthing wire above the transmission lines, however this is costly. The only way to raise availability towards the 99-99.9% is to build dual redundant power lines, using separate alignments such that storms are unlikely to simultaneously affect both lines. Such a measure would virtually double the cost of transmission.

Given the availability limitations of the transmission line, it is regressive to spend more capital on power plant availability in order to improve overall availability beyond about 96%. At this stage it is unclear whether 96% will be considered to be adequate by incumbent gas producers. It is considered that an emerging gas proponent in the Cooper Basin may have lower expectations, and similarly there is more tolerance of lower availability for satellite stations that form only one part of the total gas supply. In any event, a design availability target of 95% has been proposed, on the

basis that it should be achievable with a sensible level of capital investment in redundant equipment.

8.2.3 Evaluation of EGS Power Plants

As mentioned, achieving the highest capital efficiency, or lowest specific CAPEX, was determined to be the most important metric for the HGP project. However, when this metric is used for the surface plant in isolation without considering the wells, it can give misleading results. This is because a low cost and efficiency plant can have very low utilisation, meaning that by decreasing the specific CAPEX of the plant, the specific CAPEX of the wells is increased. It is therefore necessary to compare *total project costs* on a specific CAPEX basis.

In addition, the specific CAPEX metric does not take into consideration annual generation, or changing plant performance over time. In short, revenue is earned from MWhs sold, not MWs installed. For this reason, projects were also analysed on a levelised cost of energy basis (LCOE).

This section explains the key performance parameters of evaluating a geothermal plant and the interaction between them.

8.2.3.1 Utilisation efficiency

Utilisation efficiency is an industry standard measure that simply quantifies how much of the geothermal energy produced is turned into electricity. It is important in the HGP given the high drilling costs because higher utilisation leads to the generation of more power from the same number of wells. Conversely, it can reduce the number of wells for the same amount of power generation. This typically achieves a lower specific CAPEX across the total project.

Specifically utilisation efficiency is the ratio of actual power generated to the exergy of the produced geothermal brine, where exergy is the maximum theoretical amount of power that could be generated. Utilisation efficiency is calculated by:

$$\eta_{utilization} = \frac{\text{Power Output(kW)}}{\text{Massflow (kg/s)} \times \text{exergy (kJ/kg)}}$$, where

$$\text{Exergy} = h_{brine}(T_{prod}, P_{prod}) - h_{brine}(T_0, P_0) - T_0\left[s_{brine}(T_{prod}, P_{prod}) - s_{brine}(T_0, P_0)\right]$$

Utilisation can be improved by intelligent cycle selection, sometimes with no penalty in capital cost. It is also improved by reducing the "approach" or "pinch point:" in the heat exchangers, which usually means an increase in their surface area and thus cost. A common characteristic of a plant with high utilisation efficiency is a low reinjection temperature.

To keep the permutations manageable, the heat exchanger design and costings have been based on a brine design approach temperature of 10°C. (Some suppliers of packaged plant offered the heat exchangers as part of their scope and may have selected different approaches, as part of their own assessment of how much CAPEX to invest in the pursuit of utilisation.)

8.2.3.2 Thermal Efficiency

Thermal efficiency describes the proportion of the heat captured in the heat exchangers that is converted to electricity. All geothermal plants suffer from low efficiency compared to fossil-fuelled plant due to their low temperature heat sources ("Carnot efficiency limitation") and efficiencies are typically in the range of 6 to 20%.

The key parameters that dictate a plant's thermal efficiency are plant cycle selection, cooling method, heat exchanger approach, and local ambient temperatures (see **Figure 8-2**). Once the plant cycle is selected, higher efficiencies can be achieved by reducing cooling or heat exchanger approach temperatures. However, reducing approach temperatures results in a near-exponential cost increase and optimisation is required to achieve to lowest overall specific CAPEX (see Figure 8-3). GDY did not constrain suppliers who submitted proposals in terms of the approach, and they will have chosen different approaches as part of their own assessment of how much CAPEX to invest in the pursuit of thermal efficiency. Approach temperatures would need further careful optimisation if the project were to proceed.

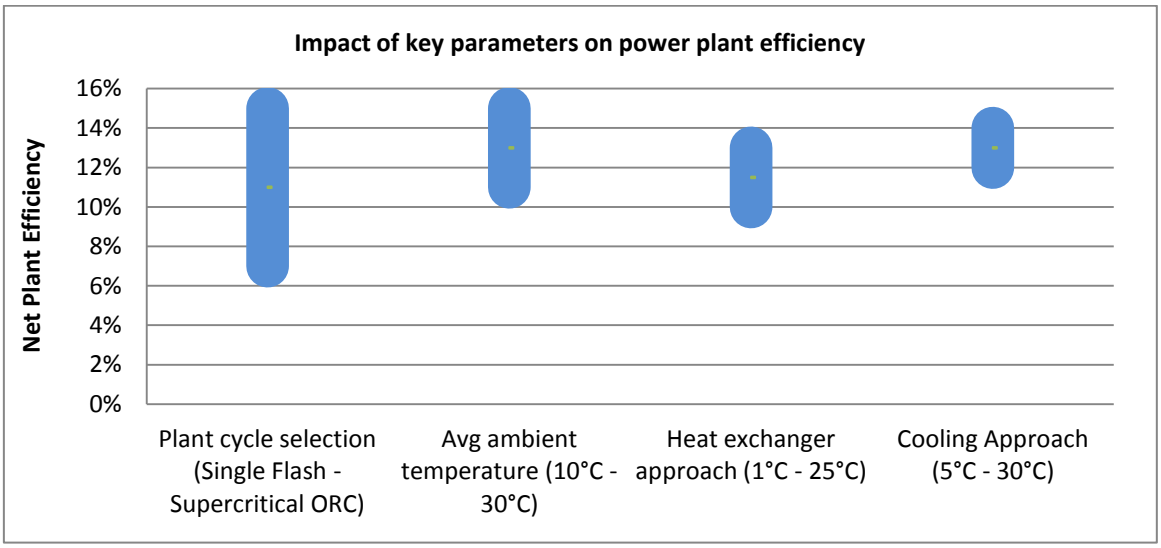


Figure 8-2: Impact of key parameters on power plant efficiency (Inhouse calcs: Thermoflow)

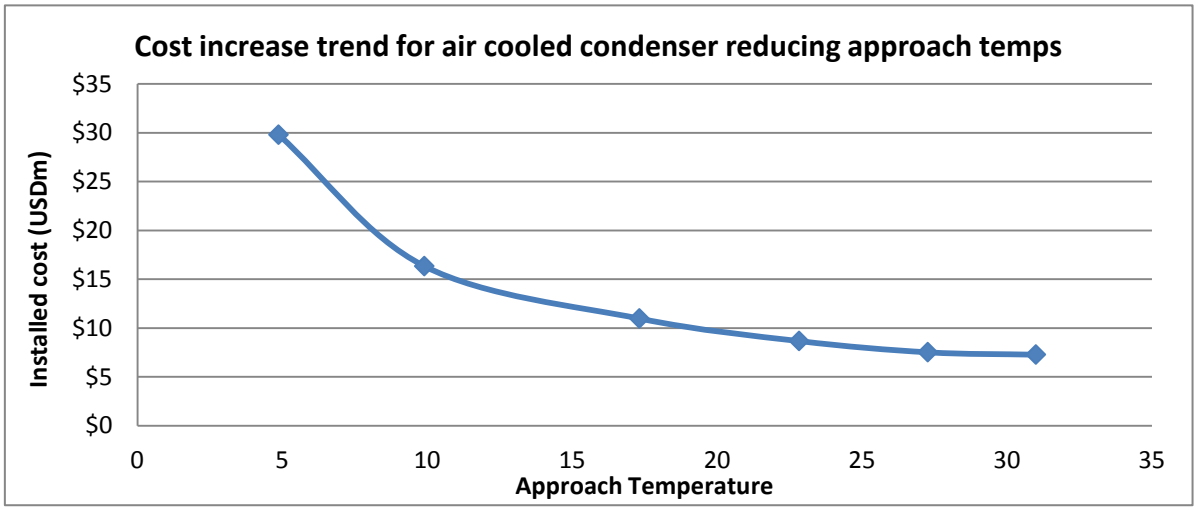


Figure 8-3: Cost of air cooled condenser vs design approach temps (Inhouse calcs: Thermoflow)

8.2.3.3 Levelised Cost of Electricity (LCOE)

The LCOE is a widely used metric to compare different technologies used for the generation of electricity. It allows the fair comparison of a high capital, low operating cost technology, such as geothermal, with a low capital, high operating cost technology such as gas. It is important with regard to the HGP because the main competition is considered to be the opportunity cost of gas. Therefore, the large upfront capital cost of an EGS project must be less than the assumed value of the offset gas over the life of the project. It can be defined as:

$$LCOE = \frac{\sum \text{Net Present Costs}}{\text{NPV generation}}$$

It is important that LCOE is considered as well as specific CAPEX because it quantifies the effects of changing plant output due to ambient temperatures, resource degradation, plant performance degradation, availability, and reliability. Conversely, the specific CAPEX metric only considers capital costs and the name plate output of the plant at the chosen evaluation temperature. That being said, because EGS projects are highly capital cost dominated, projects with the lowest specific CAPEX often also have the lowest LCOE.

However, this should not be accepted without detailed holistic analysis as for example, a plant with a high utilisation efficiency might have the lowest specific CAPEX, but because of a lower reinjection temperature, it may degrade the resource much faster leading to a much lower generation output of the project life. This type of optimisation is beyond the scope of this study and has not been considered.

8.2.3.4 Specific CAPEX

Specific CAPEX is the ratio of capital costs to the name plate plant rating at a selected ambient temperature; industry standard is 15°C. Site specific temperatures (23°C) are used in this study. Specific CAPEX is defined as:

- Specific CAPEX = Capital Cost / Net Power Output

8.2.4 Technology options

In more recent times there has been a geothermal industry push towards the more sustainable management of geothermal resources to prevent subsidence issues, prolong the life of resources, reduce drilling costs and risks, and generate as much electricity as economically possible. This has driven the uptake of more efficient and higher utilisation plants combined with reinjection of a large portion of the produced geothermal brine. In addition, increasing fossil fuel costs has made waste heat recovery projects attractive for energy savings and have stimulated suppliers to develop efficient plant options for low temperature resources.

As a result, there is now a wide range of efficient plant options with high utilisation for geothermal service available. In contrast, early plants were cheap, inefficient, and often exhausted directly to atmosphere using back pressure turbines. Recent developments in New Zealand have seen multiple triple flash plants being installed, and the European geothermal push has encouraged the development of new efficient Organic Rankine Cycle (ORC) plants for lower temperature resources.

For the purposes of the study, given the recent developments in available, the market was approached to get up to date performance and costing information. The results of which are covered later. This section describes the basic technology options available for geothermal plants for background information.

8.2.4.1 Cycle selection

One of the most important design decisions of a geothermal plant is the cycle selection. In this case, '*Cycle'* refers to the working fluid type and its operating process parameters. It is a major determinant of the thermal and utilisation efficiency of the plant, as well as the reinjection temperature. Therefore, cycle selection has an important role in the sustainable management of the geothermal resource and geochemistry issues such as scaling in the injection system.

The aim of cycle selection is to optimise thermal and utilisation efficiency within equipment limitations, and the site specific limitations of brine temperatures, site cooling, water availability, and the local climate. Typically, the brine production temperature defines the range of suitable working fluids and then other site specific limitations define the bounds of performance. **Figure 8-4** demonstrates this process for a 160°C geothermal resource using propane as a working fluid (for demonstration purposes only).

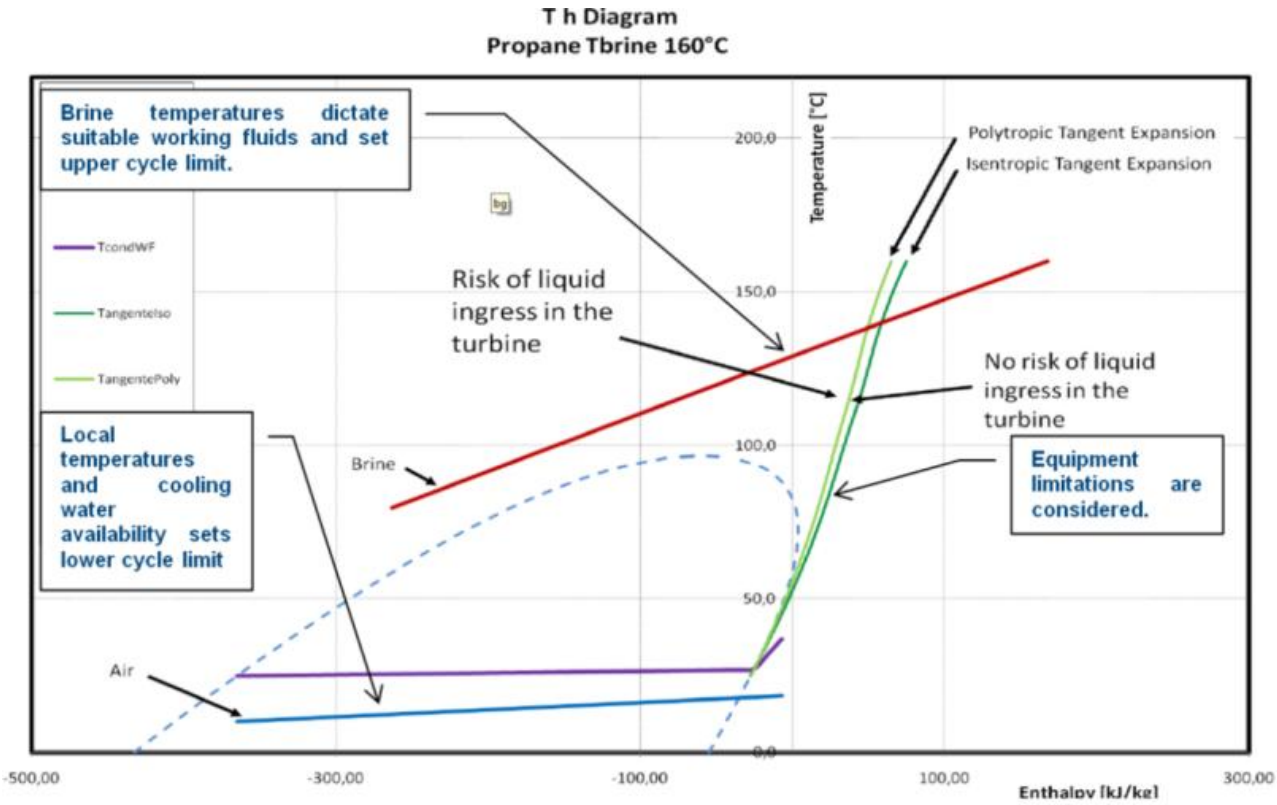


Figure 8-4: Example of setting thermodynamic limitations for cycle selection (Cryostar 2009 - Optimisation of Cycle Processes)

8.2.4.2 Steam based plants

Geothermal steam plants are based on the Rankine cycle. Direct flash steam plants are one of the most commonly used plants in geothermal applications. They are typically the automatic choice when brine production temperatures exceed ~220°C. In direct flash plants the geothermal brine is flashed in a separator before the geothermal steam is directed to the turbine. The liquid in the separator is then either flashed again at a lower pressure to generate more steam, or disposed of via reinjection. Single, double, or triple flash plants can be used. The key difference at Habanero is that the high pressure heat exchangers are required to transfer the heat from the brine to the working fluid due to the need to reinject ~100% of brine at reservoir pressure. Apart from this, the thermodynamic cycle operates exactly the same. Flash plants are typically advantageous at high temperature resources and on large scales as single shaft steam turbines can be utilised in plants over 100 MW_e in capacity. Conversely, single ORC turbines are limited to ~20 MW_e.

The existing 1MW plant is a single flash plant, and the future base case plant for Cooper Basin EGS plants was considered to be a double flash plant of 25-50 MW_e in capacity. However, the selection of this type of plant was mainly based on the fact that single shaft steam turbines can be readily procured in this size, whereas ORC turbines are limited to ~20 MW_e. Other factors in this selection included a higher design temperature of ~250°C, more supplier competition, and the attractiveness of such a proven technology. However, for this study, a smaller plant with a lower design temperature was desired. As a result, and the fact that there is now substantial competition in the ORC space, ORC plant solutions were thoroughly investigated and proved to be a superior technology.

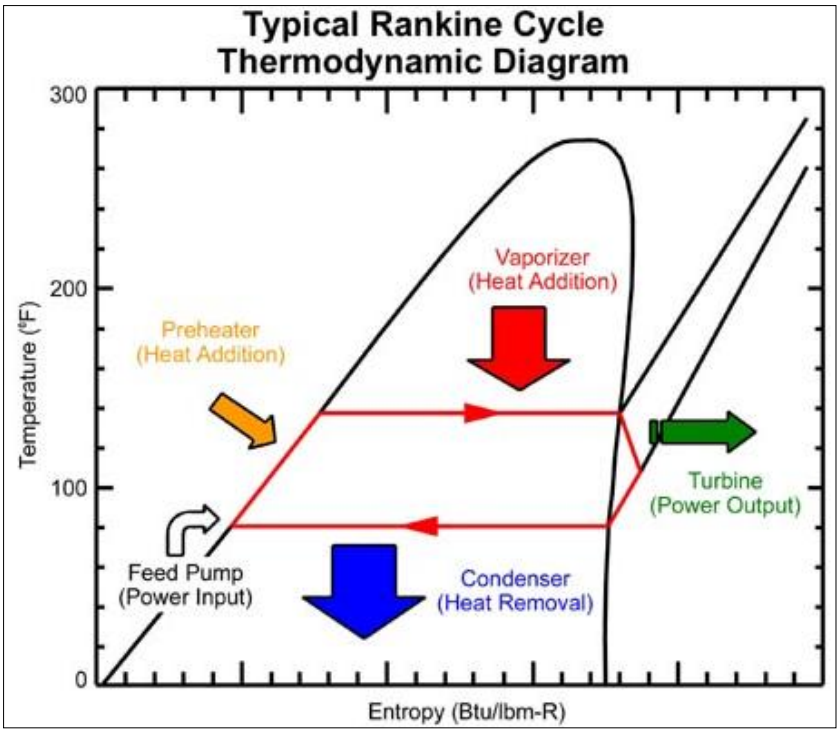


Figure 8-5: Temperature-Entropy diagram of rankine cycle (www.barber-nichols.com)

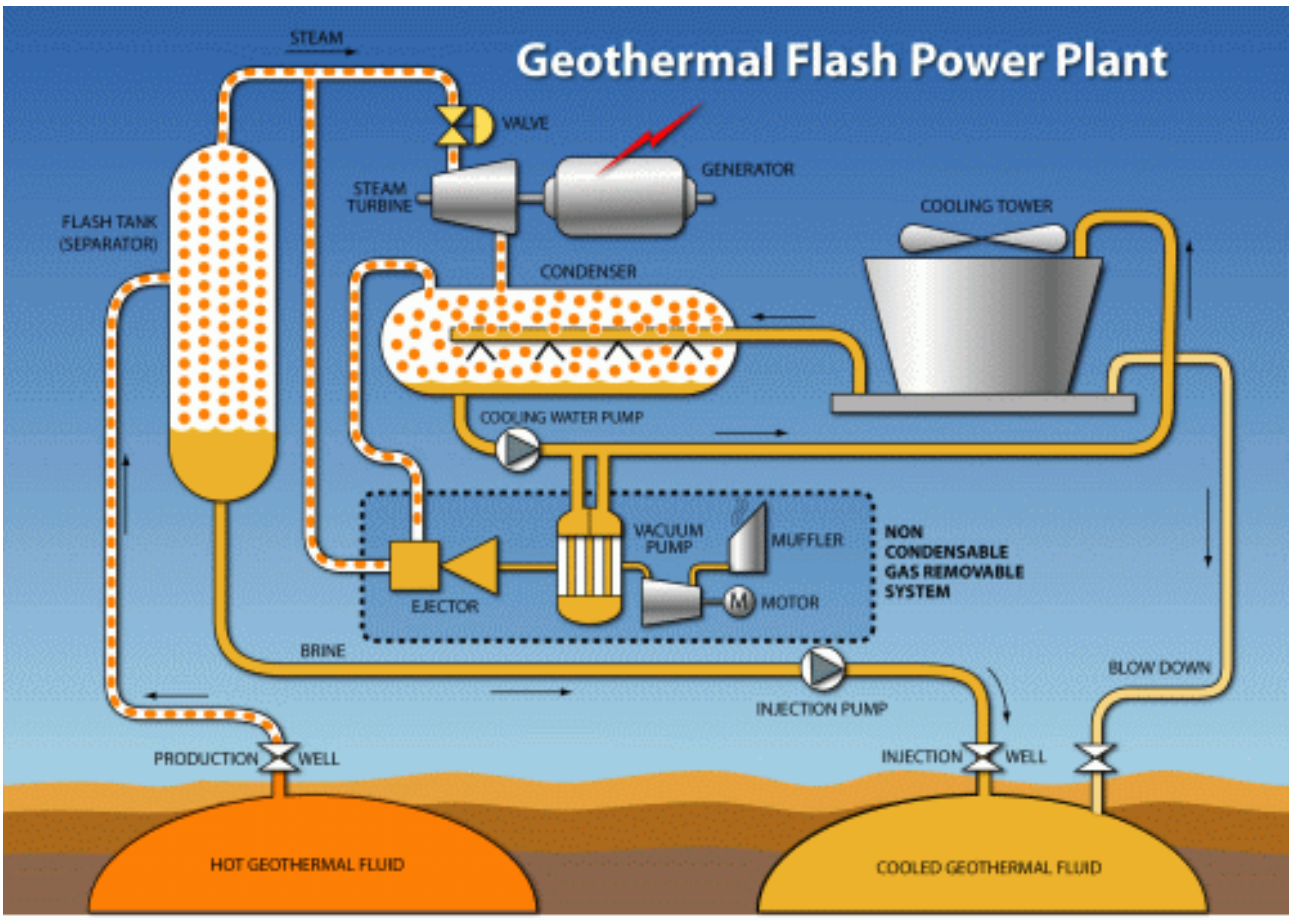


Figure 8-6: Schematic of direct flash plant (www.ormatfunding.com)

Figure 8-7: Kawerau Geothermal Plant, Upstream Developer: Kawerau Geothermal Limited (Mighty River Power), Plant Type: Dual flash separation, High pressure separator: 12 barg, Low pressure separator: 1.9 barg, Total steam flow: 1000 t/h, Brine flow: 1500 t/h (www.nzgeothermal.org.nz/nz_geo_fields.html)

8.2.4.3 ORC based plants

ORC based plants are used in a binary configuration, whereby the heat from the geothermal brine is transferred to the working fluid via heat exchangers. In the case of Habanero, the concept remains the same, except that the working fluid is different. The working fluid cycle is a closed system to prevent the working fluid escaping to atmosphere. As such, it is necessary to use an air cooled condenser, or closed water cooled condenser, rather than the open cooling water systems common in direct flash plants.

Ormat pioneered the use of ORC plants and offer well proven technology with over 1,500 MW of installed capacity. These plants are typically based on n-pentane as a working fluid at sub-critical parameters. In more recent times, numerous competitors supplying ORC based plants have come into the market place. As suppliers seek competitive advantages more advanced ORC cycles are becoming available, in particular supercritical ORC cycles using other fluids.

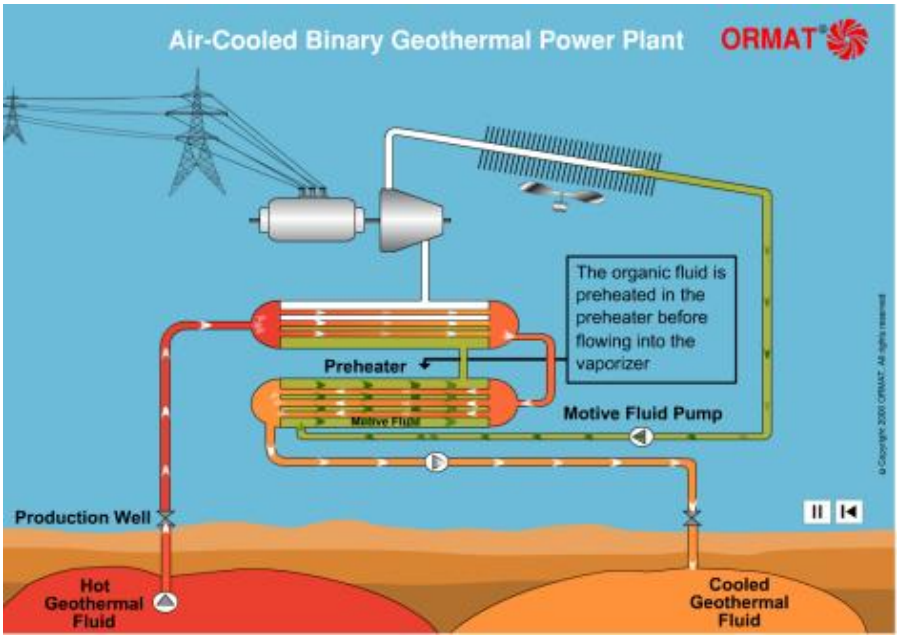


Figure 8-8: Process schematic of Ormat ORC based plant (www.ormatfunding.com)

Figure 8-9: Ormat Rotokawa Power station in New Zealand (www.industcards.com)

8.2.4.4 Supercritical ORC technology

A supercritical cycle is basically the same as a subcritical ORC cycle except that the working fluid is pumped to a pressure above its critical pressure and heated to above its critical temperature. A key feature of a supercritical fluid is that there is no distinct phase change between liquid state and vapour state. As a result the phase change in the brine heat exchangers occurs at varying temperatures, which allows a closer match between geothermal brine and working fluid, and reduces exergy losses. **Figure 8-11** demonstrates this concept; the shaded red area represents energy lost across the brine heat exchangers and the significantly reduced losses of the supercritical cycle are clear. One key issue with supercritical cycles is the parasitic power of the working fluid pumps is quite high, due to the high pressures required to reach supercritical pressures. This parasitic loss can actually be so great that it negates any improvement in cycle performance. In addition, the high pressures and large pumps add to the capital cost of the plant. Consequently, careful optimisation and consideration of these issues is required in supercritical plants.

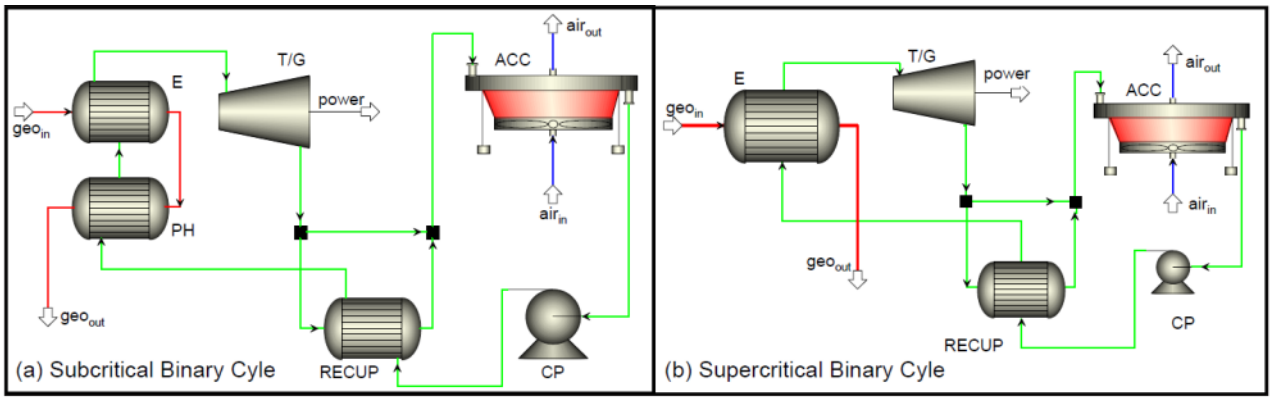


Figure 1. Process flow diagrams for (a) subcritical and (b) supercritical binary Rankine cycle power plants. (PH = preheater, E = evaporator (subcritical case) or primary heat exchanger (supercritical case), T/G = turbine/generator, ACC = air-cooled condenser, CP = condensate feed pump, RECUP = recuperator; red = geofluid, green = working fluid, blue = air).

Figure 8-10: Process schematic of sub and supercritical ORC cycles (Dipippo 2009)

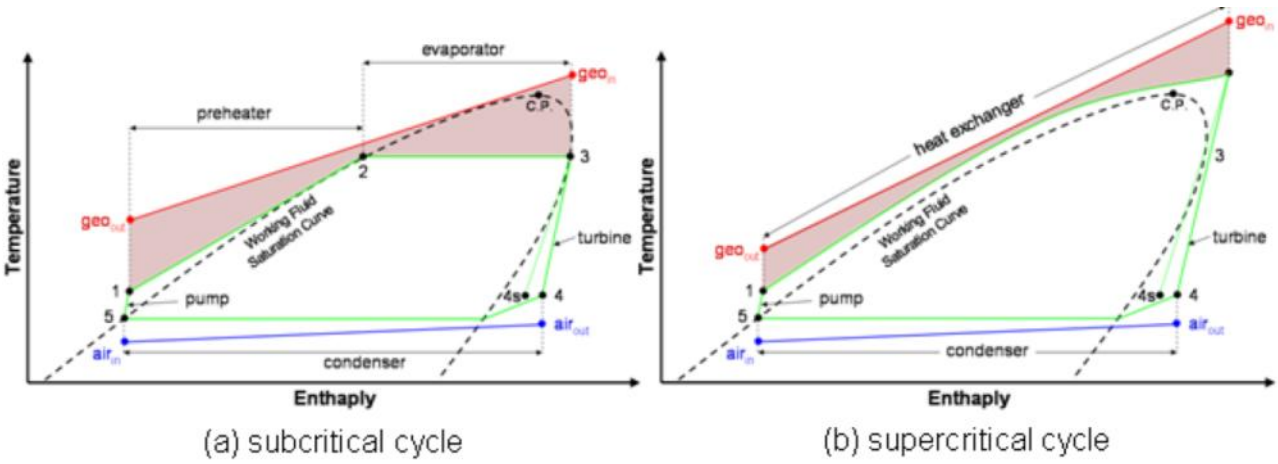


Figure 8-11: Comparison of sub and supercritical cycles (Dipippo 2009)

Supercritical cycles offer significantly improved thermal and utilisation efficiencies over subcritical plants. As a result, the increasing uptake of supercritical based cycles in conventional coal fired plants has been observed, and it appears that this trend will continue in geothermal applications. It was endeavoured as part of the study to explore the limits of supercritical technology available for geothermal applications. To do this, GDY worked with the Queensland Geothermal Centre of Excellence (QGECE), carried out market research on suppliers, sought supercritical based plant offers for Habanero, and discussed capabilities, performance, and limitations with suppliers.

QGECE confirmed the significant potential of supercritical ORC plants with some basic design and thermodynamic analysis. As shown in **Figure 8-12**, it was estimated that ~3.8 MW_e net could be generated from one pair of EGS wells flowing 40 kg/s using a supercritical R245fa fluid and a natural draft dry cooling tower. Significantly, this is over 50% greater than the target capacity of 2.5 MW_e net per pair of wells.

However, issues were encountered in getting suppliers to submit supercritical based proposals. Firstly, Echogen in the US, who provide a super critical CO_2 based cycle for low temperature applications, could not provide a proposal due to resource limitations. In addition, Cryostar, who are a known global supplier of supercritical ORC turbines, could not provide a radial turbine to match QGECE's cycle, and were not able to provide a proposal on an alternate fluid without a detailed process design supplied by others. GDY did provide basic alternate process designs but Cryostar failed to respond in time. Granite/Granex have developed an advanced supercritical ORC cycle and were approached but were unable to assist due to their technology still being at early stage. Finally, Atlas Copco are also known to be involved in the supply of supercritical ORC plant but were not approached on this occasion.

Most promisingly, TAS provided a dual pressure subcritical ORC cycle proposal utilising R245fa (and another refrigerant), and then provided performance estimates for a supercritical R245fa cycle for comparison. TAS could not replicate QGECE's performance and suggested that it was overly optimistic; although, they did state a guaranteed performance of ~3.2 MW_e at a higher design temperature, so the difference might not be that significant at somewhere less than 15%. Importantly though, TAS can supply an axial turbine to suit the process conditions with performance guarantees, believe R245fa is the optimum refrigerant, and are willing to incorporate a natural draft dry cooling tower.

With regard to supercritical ORC plants, the study established that there are significant performance improvements available, the technology is available and can be procured with performance guarantees as stated by TAS. It is recommended that should the HGP project progress, that supercritical ORC plants are investigated in more detail. A detailed process design carried out by a reputable consultant issued to suppliers such as Cryostar and Atlas Copco should achieve the required result. Also, TAS are likely to be forthcoming with a proposal with more time and more certainty of the project progressing.

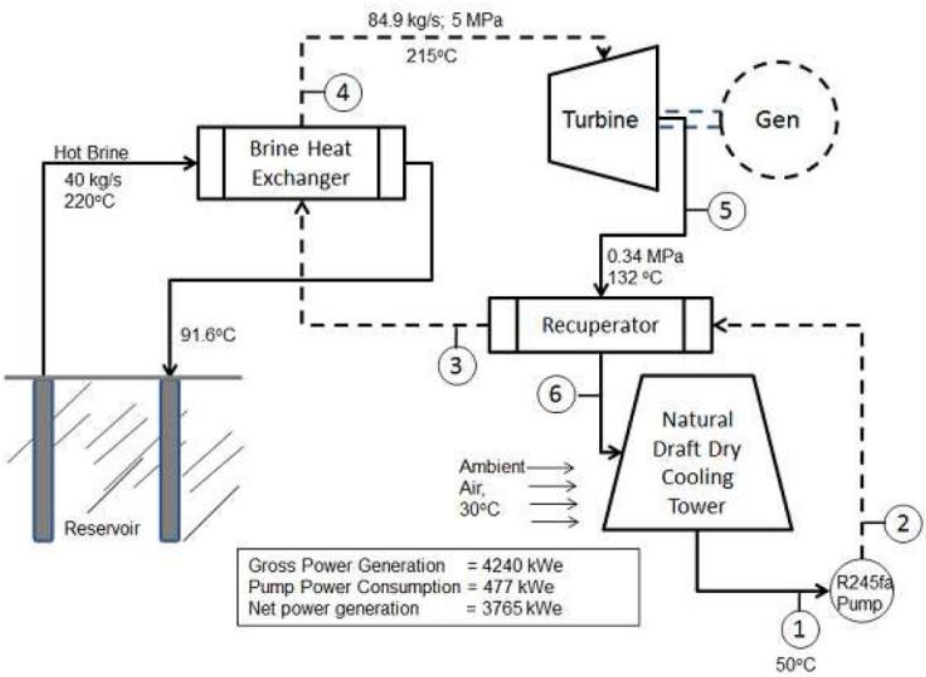


Figure 8-12: Supercritical ORC cycle design carried out by UQ's QGECE (Gurgenci 2013)

8.2.4.5 Kalina cycle

The Kalina cycle was not considered for the HGP, but is mentioned here for completeness. The Kalina cycle is also based on the Rankine cycle but utilises a mixture of ammonia and water to achieve a variable boiling temperature, reduce exergy losses, and increase plant efficiency. There is a small amount of installed global capacity, less than 20 MW_e, and operational and process control issues have been reported. This technology was not considered because it was deemed that a proposal for such a plant would not be achievable in the time available. The technology should be considered if the HGP progresses.

8.2.5 Cooling options

Cooling technology is an important component of a thermal power plant: it has a significant impact on performance, the equipment can contribute up to 30% of overall equipment costs, and it typically has the largest footprint. The basic cooling technology options include once-through cooling, evaporative cooling, wet/dry hybrid cooling, and dry cooling. In short, cooling technologies that use the most water are the best performing and lowest cost; many traditional power stations have been built on coast lines or large lakes to take advantage of the significant benefits of once through cooling.

However, the scarcity and value of water plus the increased environmental limitations of current times has led to most recently built plants in Australia having dry cooling systems. In the Cooper Basin, dry cooling is an obvious choice given the scarcity of water. However, if the environment has a low humidity, it is well suited for evaporative cooling. The benefits of using partial evaporative cooling was witnessed firsthand during 1MW plant operations where an agricultural spray arrangement installed in the air inlet of the plant cooler lowered the cooling water temperature by 2-3°C on hot days. As such, it was desired to investigate partial evaporative cooling options for the HGP.

The study had two cooling associated objectives: obtain up to date pricing and performance data on dry cooling systems as part of a packaged power plant proposal, and explore the costs and performance benefits of wet/dry hybrid and natural draft cooling towers.

Plant suppliers were asked to provide costed options for partial evaporative cooling options. However, all packaged power plant suppliers ultimately declined to propose evaporative cooling assistance, as a means of reducing the cost of their air condensers. Whilst most suppliers refused to consider the question, PHP did invest some engineering effort and verbally advised that project costs would not improve if they were to deploy their "Lu-Ve" technology. The reason for this is that there is nervousness from some vendors about the consequence of leaks caused by wet atmospheric corrosion, if the fluid in the condensers is pentane or refrigerant. PHP indicated that if driven in the direction of spray cooling, they would insist on running an indirect cooling water loop through the air coolers, and introducing a water-cooled condenser. This would have a negative effect on capex and plant performance. It is possible that vendors could be found who view this issue with less concern. TAS stated that they would be open to the concept of incorporating a natural draft cooling tower but would need to carry out a detailed investigation and discuss contractual guarantees.

In addition, cooling tower suppliers were approached directly for partial evaporative and natural draft cooling tower solutions. Baltimore Aircoil provided indicative pricing for a standard evaporative condenser and a water-saving adiabatic cooler that allows evaporative cooling to be used whenever desired based on a R134a working fluid. The cooling towers are small modular units typically employed in building services. Hamon Australia through their research division, Cottrell Dry Cooling Australia, provided a budgetary proposal for an air cooled heat exchanger for a steam based plant. Both companies expressed a willingness to explore other options including natural draft and hybrid towers but were limited by time and the uncertain nature of the project. It is recommended that further work be done with specialist cooler suppliers if the HGP progresses.

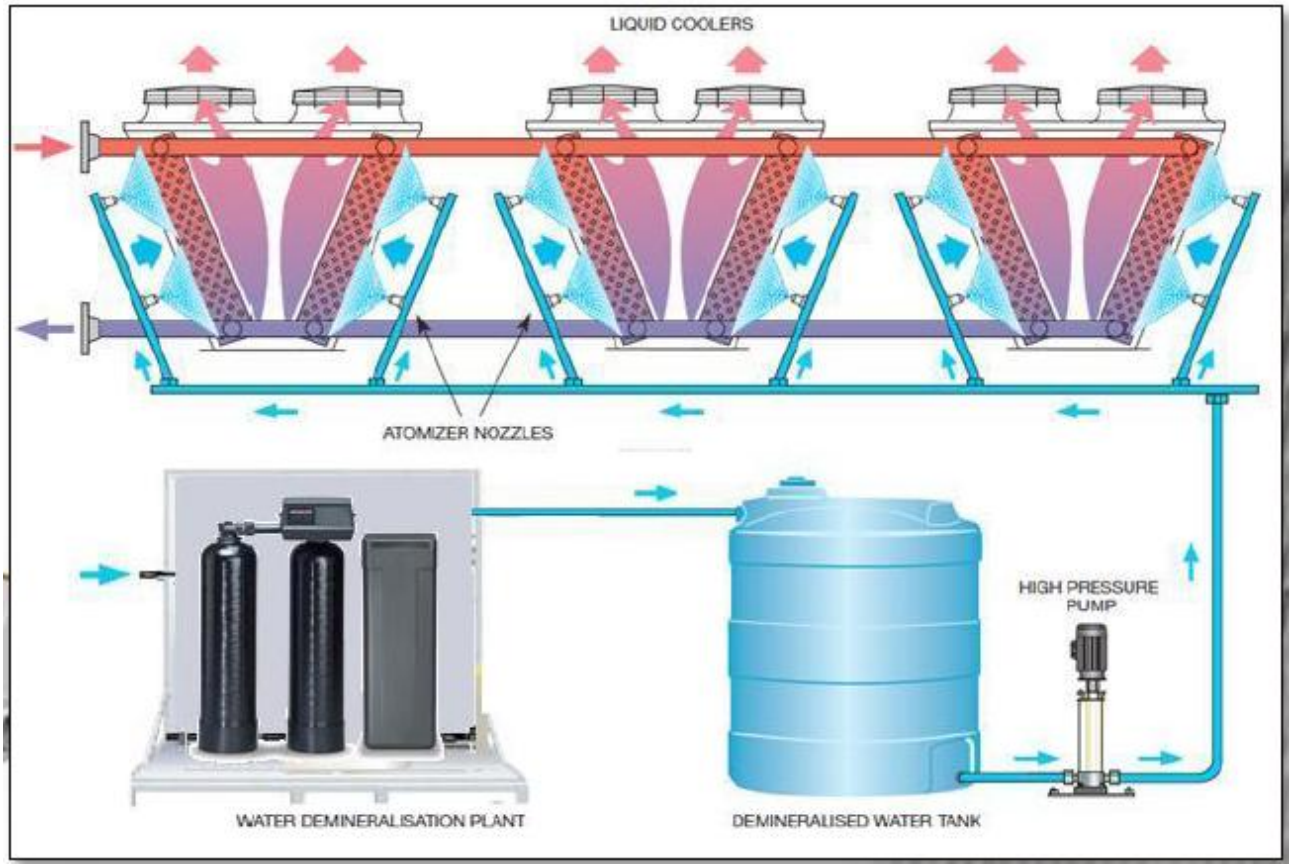


Figure 8-13: Lu-Ve Spray Cooling Process (Lu Ve data provided by PHP)

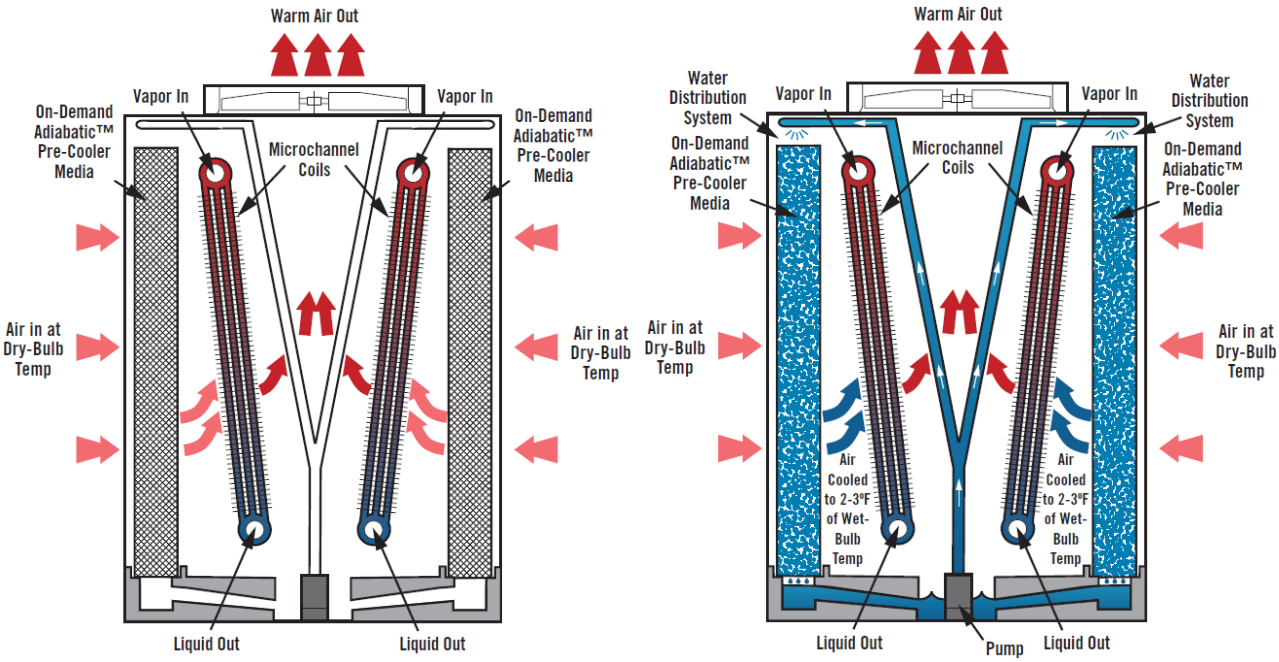


Figure 8-14: Patented dry-coil adiabatic cooling system with on-demand evaporative cooling (www.baltimoreaircoil.com/english/resource-library/file/1691)

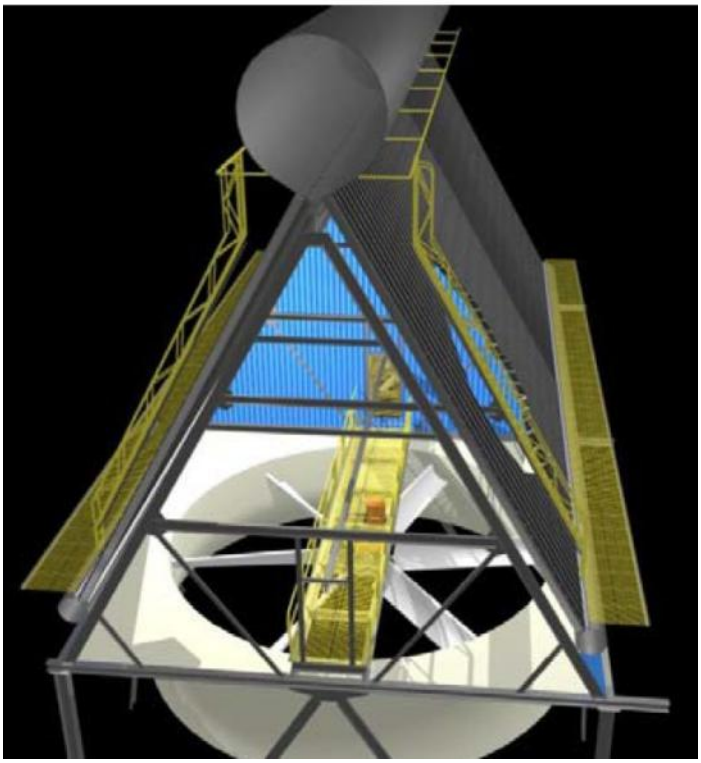


Figure 8-15: Single bay of air cooled condenser for steam based plant (Research-Cottrell Dry Cooling Australia Proposal)

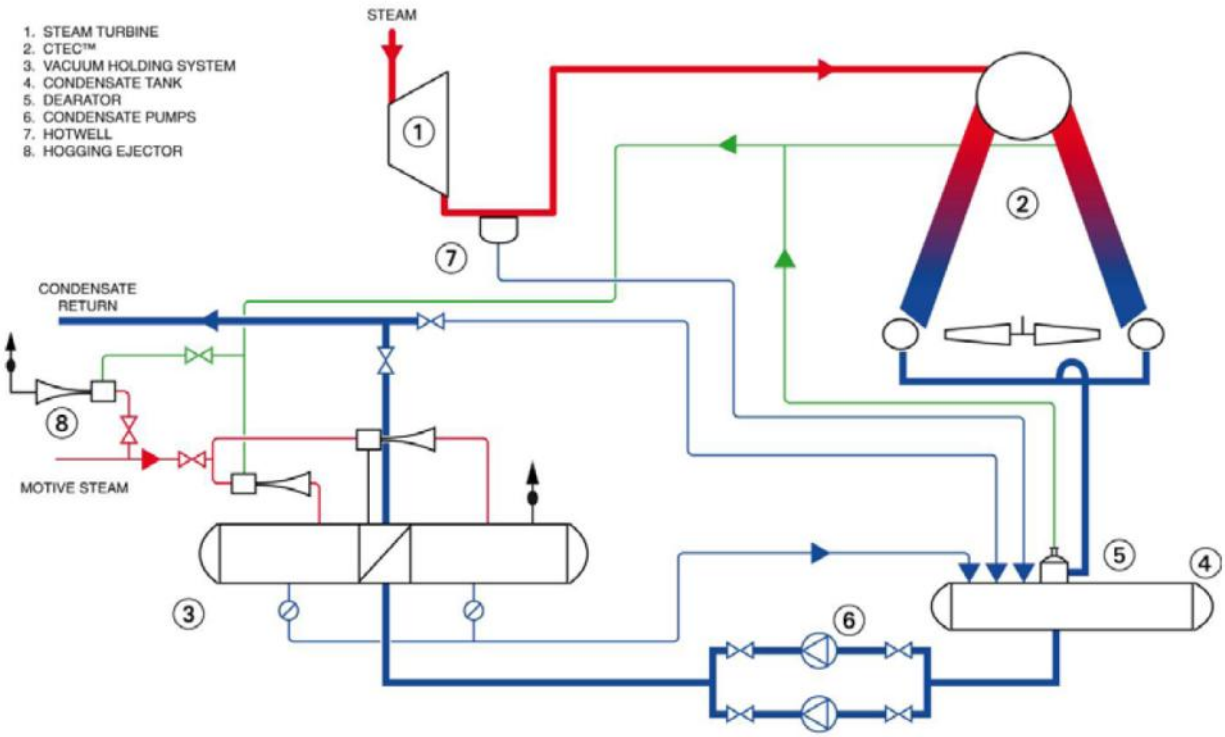


Figure 8-16: Process schematic of air cooled condenser (Research-Cottrell Dry Cooling Australia Proposal)

8.2.6 Open flow and evaporative cooling

It is proposed that the water for any evaporative cooling solution in the Cooper Basin would have to come from the resource itself as that the quantity available from local bores is not sufficient in itself. Even if it were, such use is unlikely to be acceptable from an environmental perspective. The Reservoir team have indicated that the resource has the capacity to deliver about ~10 kg/s of geothermal brine. This means that there is potentially ~315ML/annum available from a combination of geothermal brine (~85%) and local bore water (~15%).

This section discusses a preliminary investigation into the benefits and costs associated with an open flow system combined with partial evaporative cooling at high ambient temperatures.

8.2.6.1 Benefits of open flow and evaporative cooling

Open flow from the resource has numerous operational benefits: it increases net power by increasing the heat input and decreasing reinjection pump parasitic loads, it may reduce resource temperature decline and prolong its life by drawing new hotter geothermal brine into the resource from connected pressurised zones, it increases operational flexibility by allowing heat supply to the plant without the reinjection pump system in operation, it can be used intermittently to offset plant performance degradation at high ambient temperatures, and it provides the ability to control very low flow rates required for well warming.

In order to quantify the benefits of evaporative cooling, a simple comparison was carried out between dry and partial evaporative cooling plants using Thermoflow and a dual flash plant design combined with an air cooled condenser.

Figure 8-17 compares the net power output of a dry cooling-only plant, to one with partial evaporative cooling above 23°C, and also to one with partial evaporative cooling and open flow. **Figure 8-18** shows that by using open flow to increase brine flow and reduce pumping parasitic loads, and then evaporating this water in a cooling system can increase annual generation by ~10,000 MWh per year. About 30% of this can be attributed to evaporative cooling, and 70% to open flow. However, at Habanero it is difficult to have one without the other, as evaporative cooling is not possible without water, and building large evaporation dams to manage large volumes of open flow is not considered environmentally acceptable.

Based on this, partial evaporative cooling combined with open flow has the potential to generate between 15 and 20% more annual electricity than a dry cooling only plant. This equates to about ~$1.2 million in additional revenue for a six well project *assuming* an electricity price of $120/MWh.

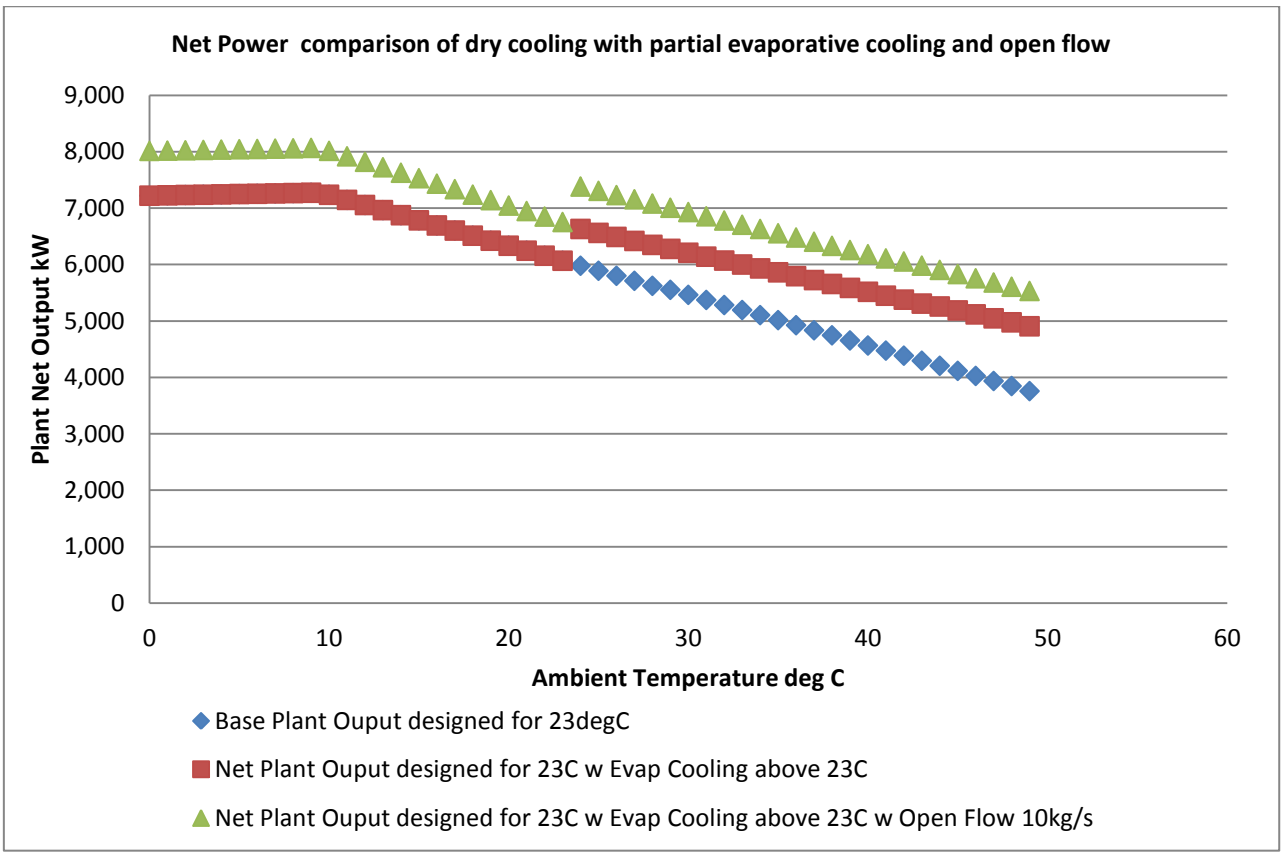


Figure 8-17: Comparison of dry cooling with partial evaporative cooling and open flow

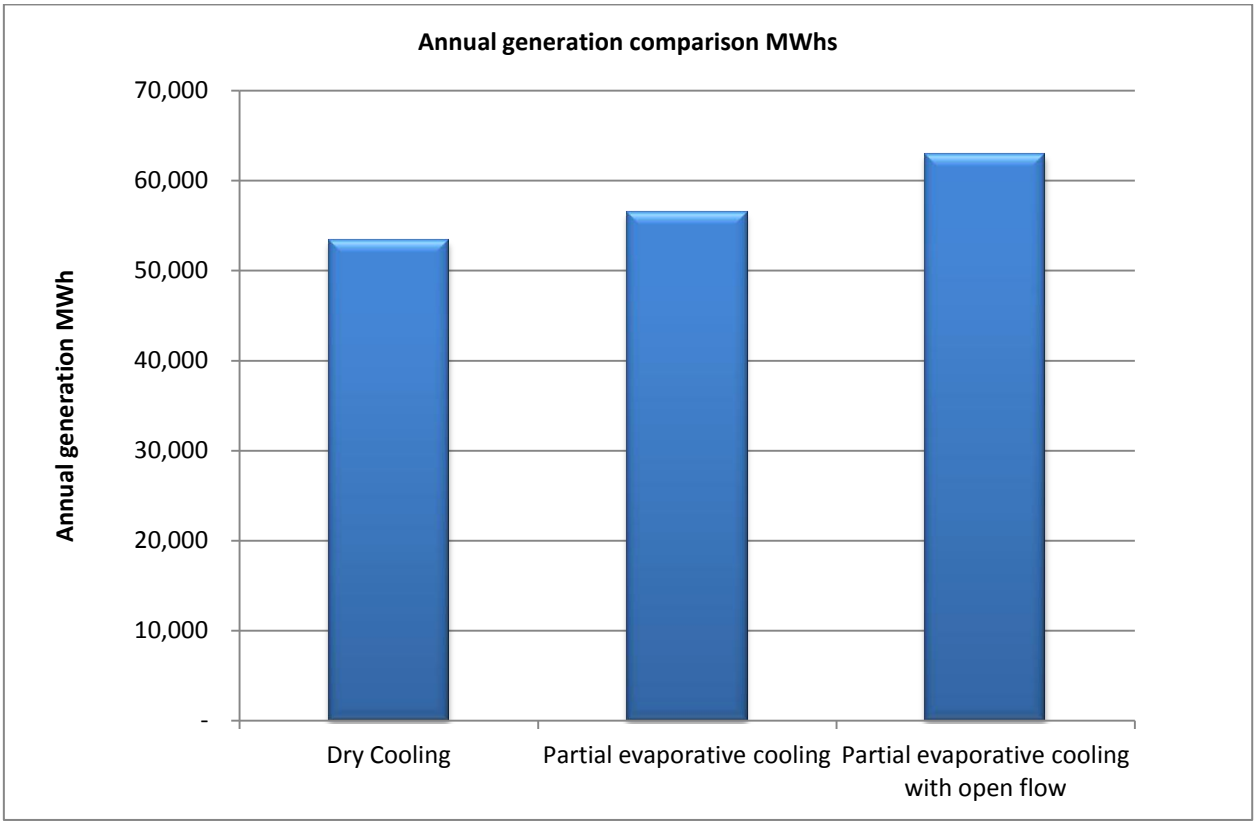


Figure 8-18: Comparison of annual generation potential for different cooling methods

8.2.6.2 Water treatment and waste disposal

Open flowing geothermal brine and utilising the water comes with a number of key issues:

- firstly, storage capacity is required to manage the large volumes of water, which adds capital and operating costs to the project; however, large dams are required for stimulation purposes and therefore a minimal incremental cost is likely to be incurred;
- there are scaling issues, mainly calcium carbonate, with geothermal brine when the pressure is significantly reduced, which is easily prevented with inhibitors but adds to operational costs;
- the water needs to be treated before it can be used for evaporative cooling, which adds capital and operating costs; however, water treatment plants are necessary for steam based plants in any case and the incremental cost for the additional capacity may not be that significant; and
- there will be hazardous waste concentrated in liquid that will need to be removed from site periodically, which adds to the operating costs; however, waste removal of stibnite waste from cleaning heat exchangers will be required in any case, and so again the incremental cost of disposing of this waste maybe relatively minor.

In order to address these issues at preliminary level and determine the feasibility of evaporative cooling at Habanero, Nalco were approached to provide a budgetary price and concept solution for treating the geothermal brine to a water specification supplied by Baltimore Aircoil. In addition, scale inhibitor and waste disposal costs were estimated based on accumulated project experiences of the 1MW Plant, HPP, and Cooper Basin in general. The results are summarised in **Table 8-1**.

Table 8-1: ROM cost estimate for water treatment and waste disposal

Item	Units	Total cost	Reference
Water treatment plant capital cost	AUDm	$2.5 - $3.5	Nalco
Water treatment operational costs	AUD/m3	$1.0 - $2.5	Nalco
Water treatment operational costs	AUDmpa	$0.3 - $0.8	Nalco
Scaling inhibitor costs	AUDmpa	$0.4 - $0.5	Assumed dosing of 40ppm, chemical prices from Nalco
Annual waste	tpa	12,600	Assumed weight of all waste solids and doubled for concentrated slurry
Annual waste disposal cost	AUDmpa	$1.0 - $2.0	Assuming 12,600tpa, 40 tonne truck, ~$5k per truck
Total CAPEX	**AUDm**	**$2.5 - $3.5**	
Total operating costs	**AUDmpa**	**$1.7 - $3.3**	

8.2.6.3 Summary

- It was estimated that for a six well project ~$1.2 million in additional revenue could be realised by combining open flow with partial evaporative cooling. However, investigations into the water treatment and waste disposal costs revealed that this concept will likely deliver a net loss to the project, in the order of $0.5 to $2.1 million per year plus the additional capital requirement of the water treatment plant.
- The key conclusion here is that a dedicated open flow system, water treatment and waste disposal system purchased and operated solely for the purposes of increasing annual generation is unlikely to be feasible in the Cooper Basin.

- That being said, if open flow, water treatment, and waste disposal was required for a dry cooled plant in any case, the benefits may outweigh the incremental cost. This would need to be looked at in more detail. Alternatively, if the geothermal brine could be used for cooling without treatment as is being investigated by QGECE, then the costs would be reduced significantly.
- In addition, if open flow could be proven to significantly impact the temperature drawdown of the resource over the life of the project, then the performance improvement over the no-open-flow option may be greater than that indicated.
- Due to the reluctance of suppliers to provide evaporative cooling options, the negative estimated financial benefits, and uncertainty around incremental costs and resource benefits, evaporative cooling was not investigated any further.

8.2.7 Potential Re-Use of HPP Infrastructure

As part of this study GDY has investigated re-using HPP equipment in future developments. Only the largest blocks are candidates for re-use. Smaller items require undue effort from the new plant designer to be integrated and the cost savings are often lost in the extra co-ordination that is required. There are also questions about the remaining life of some items (purchased second-hand for HPP) such as the water cooled condenser, and forced re-use of old equipment can complicate the negotiation of performance guarantees for new equipment.

In short, the six well development options were primarily assumed to be greenfield projects, except for the reuse of the Habanero 4 well, the high pressure brine system, and general buildings and facilities. The simple reason for this is that the 1 MW plant and 2.5 MW turbine are too small to make a significant enough cost saving to outweigh the additional complexity and cost, and inefficiencies of integration. For example, the 2.5 MW turbine could only contribute ~25%, and the 1MW plant only ~10%, of total gross capacity of new six well development.

Maximising the reuse of existing plant infrastructure was considered in the four-and-less well development options. However, as is shown later the reuse of existing plant typically leads to sub optimal outcomes due to the inherent inefficiencies combined with the complexity and cost of integration.

The items worth considering and their current statuses are listed in **Table 8-2**.

Table 8-2: HPP Equipment for Potential Re-use

Item	Current Status
Habanero 1 Pilot Injection Well	Habanero 1 can add ~10 kg/s of brine flow to a project. However, there are injection limitations and operational life issues due to corrosion of tubing.
Steam turbine generator (Peter Brotherhood, reconfigurable to 2.7 MW_e)	Suppliers were encouraged to study process schemes which re-used the turbine. Only one (GDA) pursued this (discussed below)
Brine heat exchangers	The exchanger duty for the new project(s) is the same as for HPP. The exchangers are in good condition. During HPP, only five pressure cycles were expended. These units can be re-used.
Turbine Hall	Indications are that the brine field will follow the established stimulation cloud, whose centroid is at Habanero 4 well. Since the HPP power plant site at Habanero 1 is close by, it appears viable that the turbine hall and associated spaces, such as the workshop and offices, could be re-used.
Brine piping	It is envisaged that new wells would be connected using DN200 pipe, based on the distances and flowrates involved. However, if one of the runs is shorter, there is scope for re-using the DN150 pipe used on HPP.
Brine reinjection pump, seal skid and seals	A key outcome of the HPP Knowledge Capture process is that the current pump technology, using a Horizontal Pumping System (HPS) is fit for commercial use when appropriately duplicated and that alternative pumping technology would not be pursued unless a larger project (25 MW) was being developed. During the HPP, four seals of two separate designs failed. However after modifications, the "double seal" developed by Eagle Burgmann completed the remainder of the trial without failure and is considered to be suitable for commercial use, with the caveat that it be generously spared and that further fine tuning in the design will need to occur.
Chemical Cleaning Skid	Suitable for relocation and re-use
Open flow skid and diffuser	Suitable for relocation and re-use, assuming open flows of 20 kg/s or less.
Switchgear and Transformers	The current transformers are only rated to 1 MVA and are only suitable for reuse in a small project of ~800 kW_e export. In addition, the step-up transformer is only 11 kV, and is likely not to be suitable for the transmission of power for extended distances. In the event of project progression, these assumptions will need to be verified by an electrical engineering study.

8.3 Methodology for FDP Study

This section explains the methodology used by Surface Engineering to identify, define, conceptually design, and cost options for the Habanero Geothermal Project.

The process that the Surface Engineering team followed in order to complete the study can be described as follows:

- Preliminary concepts and targets (see **Figure 8-19:**).
- Refine concepts with feedback from reservoir, drilling and management personnel.
- Collate costing information from suppliers for main equipment supply; knowledgeable construction contractors for transmission, brine piping and plant installation; reputable consultants for various other packages; and in-house information gained throughout the HPP and other previous projects.
- Conceptually design and cost options.
- During the brainstorming, the following key options were identified:
- Base case project consisting of six wells and new power plant supplying electricity to Moomba.
- As above, but to a more local gas producer in the future (i.e. with smaller transmission component).
- A four-well project and power plant, with a focus on integration of existing suitable equipment, supplying electricity to Moomba.
- As above but to a more local gas producer in the future (i.e. with smaller transmission component).
- A two-well project providing electricity to a more local user such as a satellite station.
- An existing doublet (Habanero 4 and Habanero 1) project focused on extended research and development.
- A six-well direct heat project providing heat in the form of hot water to Moomba.
- As above but with the heat provided to a more local gas producer in the future and integrated into a new plant.
- In addition to these base concepts, the following variations were identified and explored:
- Electricity supply to a smaller load that would otherwise use expensive diesel generation, such as the proposed KJM logistics facility, as part of a larger project.
- The potential for using partial evaporative cooling to enhance power plant performance and reduce cooling tower CAPEX.
- The potential for hybridising an EGS plant with other technologies.
- The potential for using partial and temporary open flow to increase plant output at times of high ambient temperatures and provide water for evaporative cooling.

It was identified early in the study that there were a number of key areas that should be focussed on in the study because they had the greatest potential for improvement or were significant cost items with a high level of uncertainty in the estimated price. These key areas are explained in more detail in this section and are listed here:

- Packaged Power plant design
- Balance of plant within plant boundary
- Heat exchanger design and manufacturing costs

- Brine field piping
- Direct heat pipeline to Moomba
- Transmission

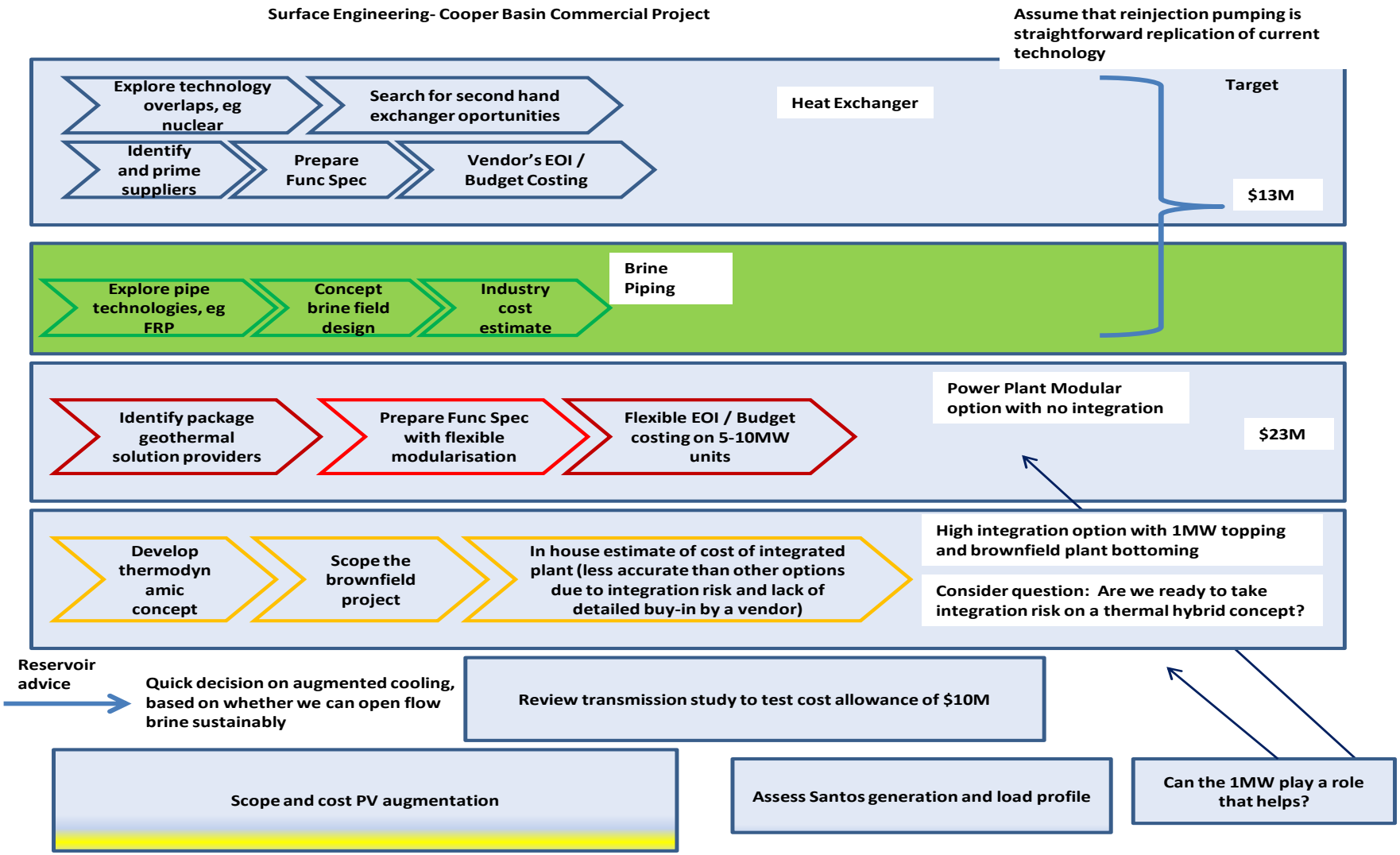


Figure 8-19: One page study strategy after initial concept discussions (which subsequently evolved)

8.3.1 Design and costing methodology

The following standard was used for assessing the accuracy of the cost estimating for each option: *AACE International Recommended Practice No. 18R-97 Cost Estimate Classification System – As Applied In Engineering, Procurement, And Construction For The Process Industries* (See **Figure 8-20**).

Most of the detailed work was focused on the base project, other options were considered in less detail and leveraged of information gained from base project investigations. A summary of the costing methodology for each option is listed in **Table 8-3**.

	Primary Characteristic	***Secondary Characteristic***			
ESTIMATE CLASS	**LEVEL OF PROJECT DEFINITION** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges [a]	**PREPARATION EFFORT** Typical degree of effort relative to least cost index of 1 [b]
Class 5	0% to 2%	Concept Screening	Capacity Factored, Parametric Models, Judgment, or Analogy	L: -20% to -50% H: +30% to +100%	1
Class 4	1% to 15%	Study or Feasibility	Equipment Factored or Parametric Models	L: -15% to -30% H: +20% to +50%	2 to 4
Class 3	10% to 40%	Budget, Authorization, or Control	Semi-Detailed Unit Costs with Assembly Level Line Items	L: -10% to -20% H: +10% to +30%	3 to 10
Class 2	30% to 70%	Control or Bid/ Tender	Detailed Unit Cost with Forced Detailed Take-Off	L: -5% to -15% H: +5% to +20%	4 to 20
Class 1	50% to 100%	Check Estimate or Bid/Tender	Detailed Unit Cost with Detailed Take-Off	L: -3% to -10% H: +3% to +15%	5 to 100

Notes: [a] The state of process technology and availability of applicable reference cost data affect the range markedly. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope.

[b] If the range index value of "1" represents 0.005% of project costs, then an index value of 100 represents 0.5%. Estimate preparation effort is highly dependent upon the size of the project and the quality of estimating data and tools.

Figure 8-20: Cost estimate classes and expected accuracy range

Table 8-3: Options considered, design methodology and expected cost accuracy range

#	Description	Reference for performance and cost information	Level of definition & expected accuracy
1 & 1A	Base case project consisting of six wells and new power plant supplying electricity to Moomba, or to a more local gas producer in the future (i.e. with smaller transmission component).	Approached 10 plant suppliers for proposals; received 5. Transmission quote received from Cowell Electrical (installer of 1 MW transmission line). Heat exchanger costs from Indian and New Zealand fabricators. Brine piping and plant installation cost estimate from CBH (construction contractor for HPP) Reinjection pump and seal proposals, and valve quotes, used from previous projects. Additional costs estimated inhouse.	Class 4 +/- 30%
2 & 2A	Four well project and power plant, with a focus on integration of existing suitable equipment, supplying electricity to Moomba, or to a more local gas producer in the future (i.e. with smaller transmission component).	Unit pricing achieved from option 1. Price for refurbished turbine from GDA. Local supplier quotes for air cooled condensers. Power plant design and costing software. Inhouse data.	Class 5 +/- 30%
3	Two well project providing electricity to a more local user such as a satellite station.	Unit pricing achieved from option 1. Local supplier quotes for air cooled condensers. Power plant design and costing software. Inhouse and publicly available data.	Class 5 +/- 50%
4	Existing (H04-H01) doublet project focused on extended research and development.	Power plant design and costing software. Inhouse and publicly available data.	Class 5 +/- 50%
5 & 5A	3 doublet direct heat project providing heat in the form of hot water to Moomba, or to a more local gas producer in the future and integrated into a new plant.	SKM provide cost estimate for pipeline to Moomba. Brine heat exchanger costs from Option 1. Brine piping and plant installation costs from CBH. Reinjection pump and seal proposals, and valve quotes, used from previous projects. Additional costs estimated in-house.	Class 5 +/- 50%

8.3.2 Design Assumptions for Base Project

Geothermal (and EGS) projects present a multi-variable challenge. In order to progress with power generation design and costing, base case assumptions must be made for key reservoir and drilling parameters, together with a manageable number of 'off-design' cases.

The base case assumptions for the study were as follows:

- Brine flow per production well is 35 kg/s, or 105 kg/s for six wells, with uncertainty range of +/- 15 kg/s
- Brine production temperature of 220°C, with an uncertainty range of +/- 10°C
- Design availability of 95%
- Design Life of 15 years
- 3 mm corrosion allowance for carbon steel material
- All equipment packages to be road transportable to the Habanero site, albeit as over-dimensional loads.
- Brine heat exchanger approach temperature of 10°C
- Minimum brine reinjection temperature to prevent scaling of 50°C (to be checked if any proposal intends to inject below 80°C.
- A design relative humidity of 32%, reflecting the arid climate
- Supply of up to 315 ML/annum of water for evaporative cooling, comprised of 85% open-flowed brine and only 15% bore water
- An ambient design temperature of 35°C. This was based upon the 90% exceedance temperature in the area. However, this would need to be optimised in future studies as using the average design temperature would lead higher annual generation and a lower capital cost, but may not meet the customers' needs at higher ambient temperatures.

8.3.3 Packaged Process Plant Methodology

In order to understand the full range of power technology available for EGS plants, GDY drafted a performance based functional specification for the power plant, and issued this as a Request for Budgetary Proposal (Document CMW-FN-OT-RFQ-00826) to broad range of plant suppliers known to be specialists in different power generation technologies (see **Table 8-4**). The intent was to identify the most cost effective technology available now, and those that may be available in the short term.

Suppliers were given freedom to vary the plant power outputs around the nominal value of 7.5 MW, but were requested to maximise the ratio of power to CAPEX, while achieving high utilisation efficiencies. This was based on a fixed quantity of available brine. Suppliers were given complete freedom in cycle selection and different suppliers were encouraged in different directions, in order to produce the widest possible range of technologies for consideration. For example, GDY worked with GDA to solicit a dual flash proposal involving re-use of the existing HPP steam turbine and worked with PHP to study the options for evaporative cooling using the limited supply of water on site.

This process resulted in receiving four complete proposals that covered a wide range of available technologies including steam based, standard and advanced ORC, and modular and custom plants, and performance data on supercritical ORC plants. These proposals were assessed on a quantitative and qualitative basis.

TAS submitted a comprehensive proposal and worked with GDY to refine it. Their initial proposal involved a cascaded cycle with two refrigerants, R245fa and R134a, for a mid range performance of ~6.4 MW_e net power. This was improved by ~8% to high range performance by using a supercritical refrigerant (R245fa) in a twin parallel turbine arrangement. The good power, thermal efficiency and brine utilisation suggest that this R245fa is a good match for Habanero conditions. This finding correlates with independent work done by the QGECE, who advocated this fluid for the project. TAS included the brine heat exchangers in their proposal and was not concerned with the extreme process conditions.

PHP/Turboden also offered a comprehensive proposal, and expended significant effort to understand the Habanero EGS project specifics and to investigate evaporative cooling. Their cycle is based on n-pentane and produces a mid-range net power of 6.25 MW_e. PHP also included the brine heat exchangers in their proposal.

Ormat offered their traditional n-pentane based ORC technology with the simple arrangement of a single machine, with mid range performance of ~6.4 MW_e net power. However, based on Ormat's generic type proposal and lack of engagement through the process, the proposal is considered to have a lower level of accuracy. Ormat's current position is that Habanero brine cannot be passed directly through their exchangers, but must instead transfer its heat into an intermediate water circuit, which incurs inefficiencies, and additional costs. This position would probably change with further negotiation.

Fuji/Sumitomo offered a dual flash steam cycle, which provided low range performance of 5.4 MW_e net power. Fuji's offer and inhouse work suggest that dual flash steam is not the optimal cycle for the Habanero resource. Fuji declined to include the brine heat exchangers in their scope.

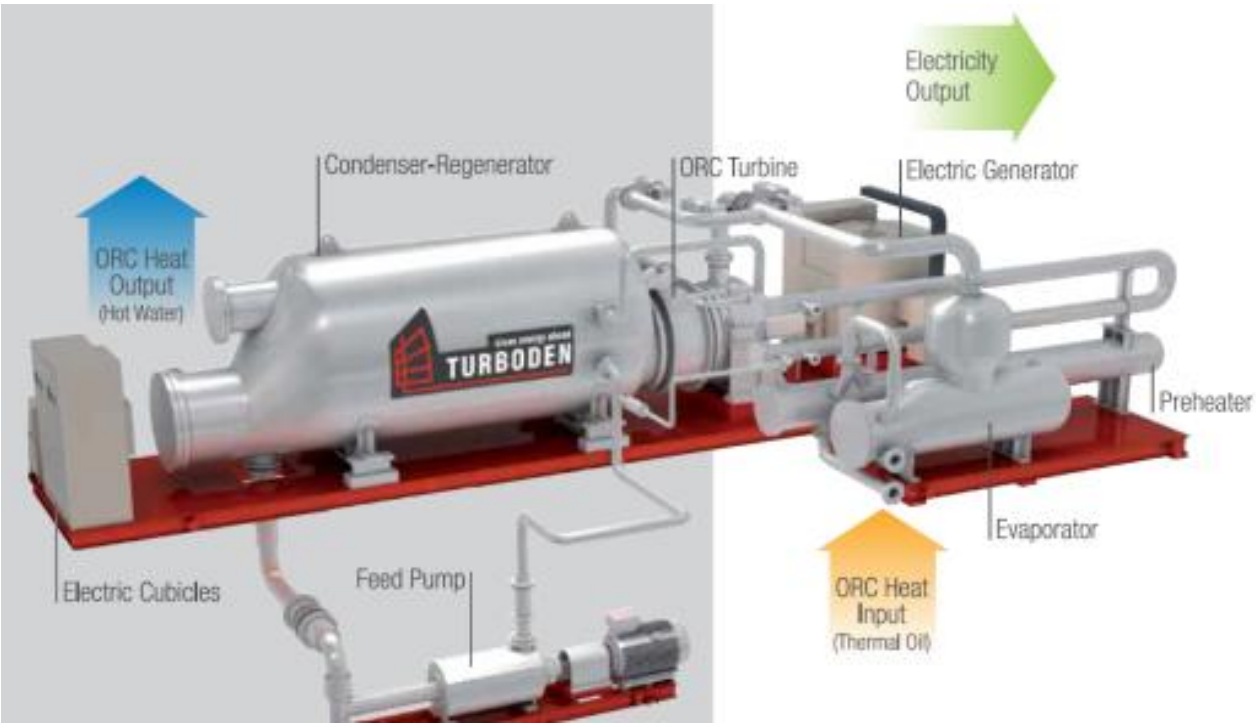


Figure 8-21: Modular ORC plant technology supplied by PHP (www.turboden.eu)

Table 8-4: Power plant suppliers approached for proposals

Company Invited	Technology speciality
Geothermal Development Associates (GDA)	Optimising and executing of projects based on second hand equipment
Fuji Heavy Industries/ Sumitomo	Standard steam based plant
Alstom / GE	Standard and advanced steam plant
Ormat	Industry leader in ORC technology
Green Energy Group (GEG)	Small, modular steam plant based on well head generation
Pacific Heat and Power (PHP)/ Turboden/ MHI	Supplier of modular ORC plants for geothermal and waste heat
Granite / Granex	Developer of advanced ORC supercritical power cycle
Cryostar	Specialist supplier of supercritical radial turbines
Echogen / UQ	Specialist supplier of supercritical CO_2 based plants
TAS	Supplier of supercritical and advanced refrigerant based ORC plants
PT Rekayasa	EPC supplier with significant geothermal experience

8.3.4 Quantitative comparison of power plant technology options

8.3.4.1 Performance comparison of power plant technology options

Figure 8-22 compares the performance of each plant option at average ambient temperature conditions. Ormat, TAS subcritical, and PHP all offer similar net power outputs of ~6.2 to 6.4 MW_e. The TAS supercritical plant offers noticeably better net power of ~6.9 MW_e.

"Net power" here refers to power after parasitic pumping losses for brine reinjection.

Also noticeable, is that the TAS subcritical plant has a much higher auxiliary load than the other subcritical ORC plants of Ormat and PHP. This is indicative of high utilisation and low efficiency plant and should result in a higher cost plant, which is indeed the case compared to the Ormat plant.

Figure 8-23 compares the net thermal efficiency, net utilisation efficiency, and brine reinjection temperature for the plant options. Ormat's plant has the highest thermal efficiency of ~11.5%, which is similar to the TAS supercritical plant, ~11.1%, and the PHP plant, ~11.2%. With regard to brine utilisation efficiency, the TAS supercritical option performed the best at 28.8%, followed by all the ORC subcritical options of ~26-26.6%.

Importantly, the Ormat plant achieves good performance while maintaining a relatively high reinjection temperature of ~96°C. The TAS subcritical option reduces the reinjection temperature to 60°C, which is likely to cool the resource much faster. The TAS supercritical option reinjects brine at ~80°C combined with excellent utilisation efficiency and good thermal efficiency.

The TAS supercritical option achieves the best performance, but does reinject at a noticeably lower temperature than the Ormat plant, which still offers good performance. Reservoir modelling to determine the effect on the differing reinjection temperatures on reservoir drawdown should be carried out before a final decision on plant technology is made.

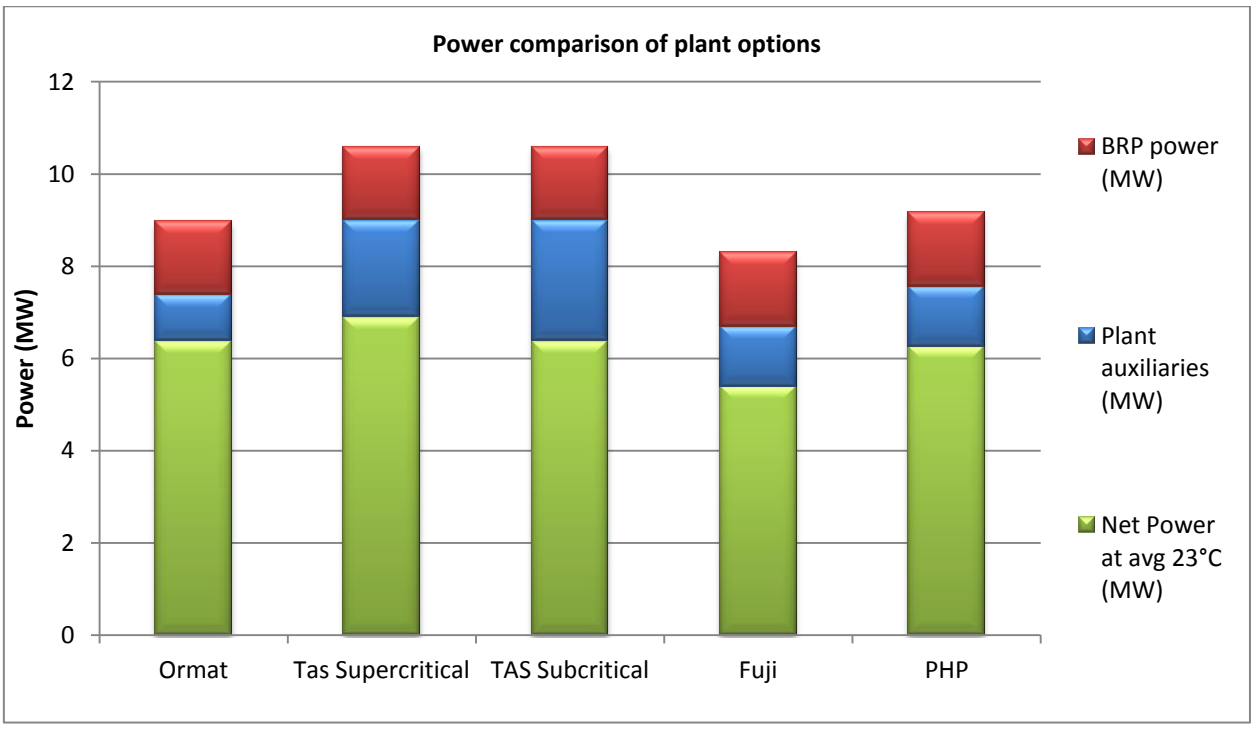


Figure 8-22: Power comparison of plant options

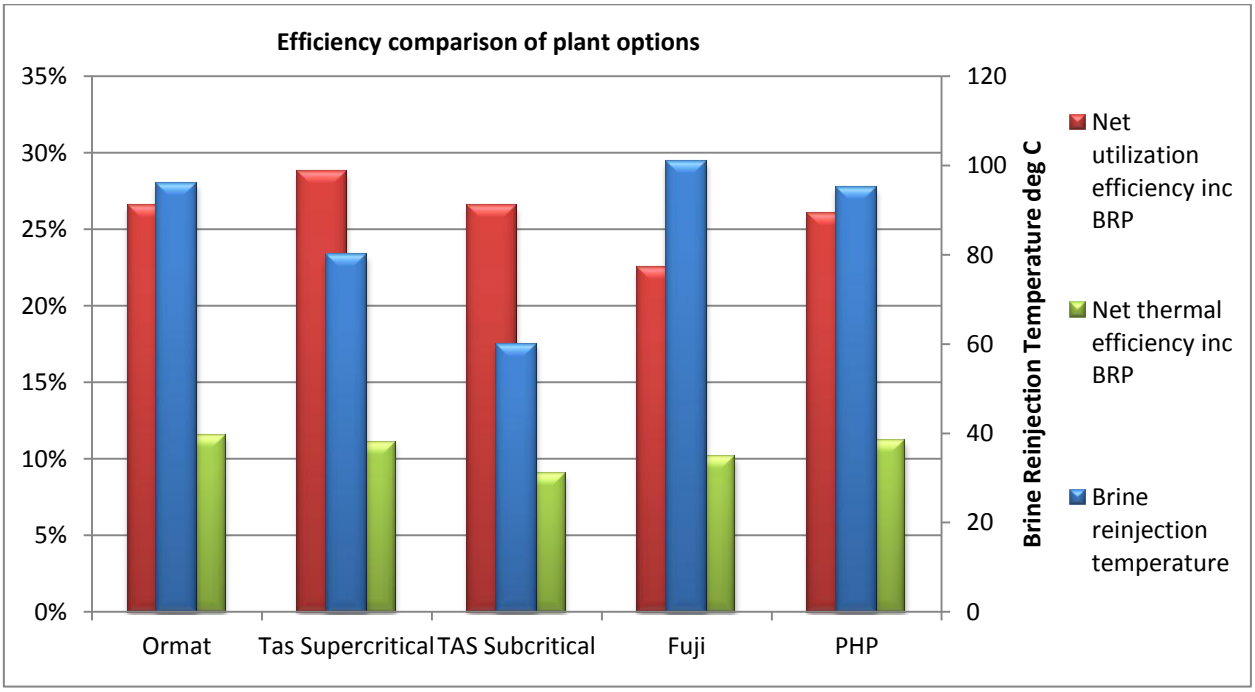


Figure 8-23: Efficiency comparison of plant options

8.3.4.2 Off Design Performance

It is important to compare differing thermal power plant technologies over the full range of expected ambient temperatures to compare the total annual generation potential. **Figure 8-22** compares the performance of the technologies at differing ambient temperatures. In the absence of data for the supercritical TAS cycle, Ormat's plant performance is the best over the range of temperatures. Noticeable is that the steam based flash plant performance is much closer to the ORC based plants at higher temperatures indicating that this cycle does not derate as much as ORC cycles.

In addition, as the output from geothermal wells is quite uncertain, it is important to understand a power plant technologies ability to handle differing brine conditions to design. **Figure 8-23** shows that the Ormat cycle is superior over most brine conditions, but performance changes away from design point are relatively higher suggesting that off design brine conditions affect it more. PHP's performance change is a straight line, and the increase in performance of the steam-based Fuji plant seems to flatten off at higher flow rates and temperatures.

In summary, the off-design trends support that the optimum plant at average design conditions is likely to be the optimum plant over most off-design conditions. Note that the power figures presented here do not account for brine reinjection pump power as it changes with varying brine conditions and is the same for all options. TAS did not provide off design data; this should be obtained and analysed before selection of their plant.

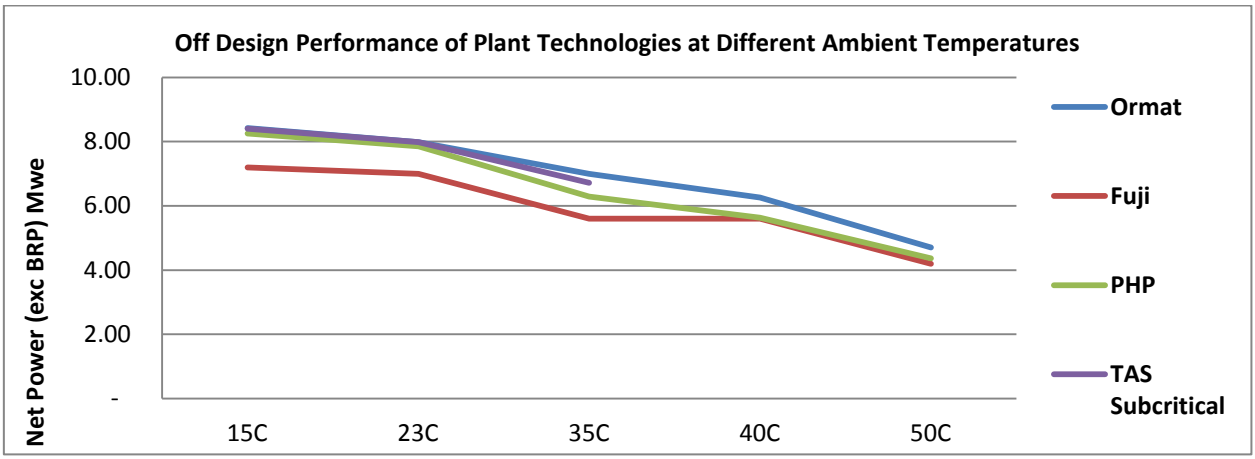


Figure 8-24: Off Design Performance of Plant Technologies at Different Ambient Temperatures

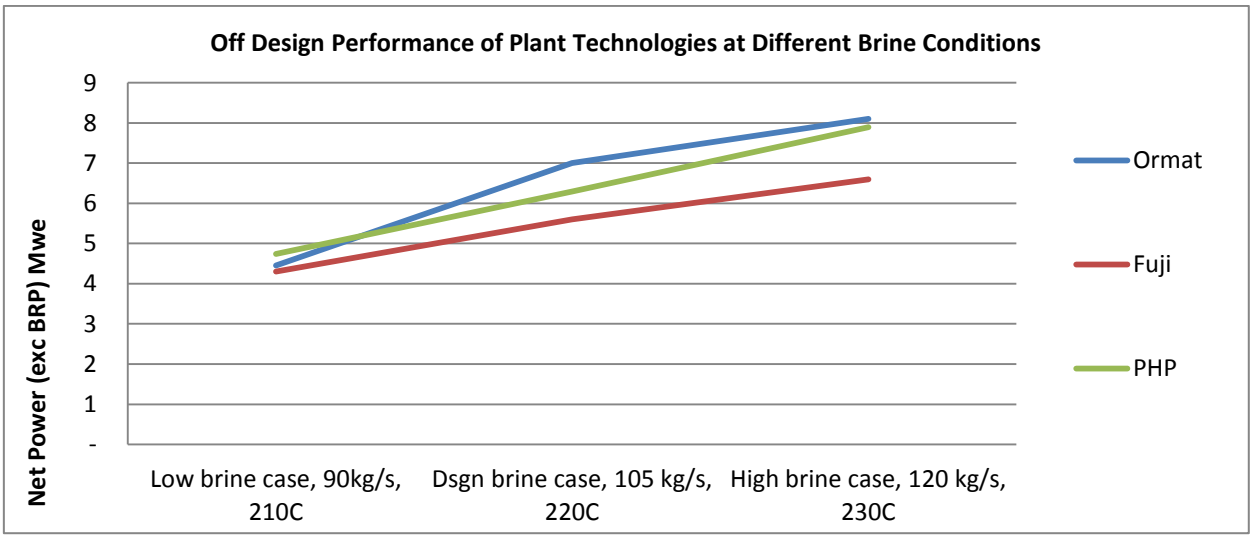


Figure 8-25: Off Design Performance of Plant Technologies at Different Brine Conditions

8.3.4.3 Summary comparison of plant technology options

Table 8-5 compares the key parameters for all plant options. The TAS supercritical option provides the best overall performance and the lowest specific cost when all project costs are considered. In addition the plant is based on 2 x 50% units which provides redundancy. However, there a higher potential technical risk given the more novel nature of the technology. Ormat offers a simple, proven plant of mid range performance with the second best project specific CAPEX.

Notwithstanding, further investigation is required for the TAS supercritical proposal, its apparent advantages, as described above, and also in the following section, have led GDY to adopt the costs of this proposal for the base case project cost and performance estimate.

Table 8-5: Comparison of plant options

	Ormat	Tas Super-critical	TAS Sub-critical	Fuji	PHP
Cycle description	Single ORC Low speed turbo-expander No gearbox	2 x Parallel ORC Axial turbines Fixed inlet geometry	2 x series ORC Axial turbines Fixed inlet geometry	Water-water binary dual flash with single turbine	2 x parallel ORC Low speed turbo-expander No gearbox
Working Fluid	Subcritical nPentane	Supercritical R245fa	R245fa & R134a	Water	Subcritical Pentane
Gross Power at avg 23°C (MW)	8.98	10.60	10.60	8.30	9.17
Plant auxiliaries (MW)	1.00	2.09	2.62	1.30	1.32
BRP power (MW)	1.60	1.60	1.60	1.60	1.60
Net Power at avg 23°C (MW)	6.38	6.91	6.38	5.40	6.25
Brine reinjection temperature (°C)	96	80	60	101	95
Net utilization efficiency inc BRP	26.6%	28.8%	26.6%	22.5%	26.0%
Net thermal efficiency inc BRP	11.5%	11.1%	9.0%	10.2%	11.2%

8.3.5 Balance of Plant within Plant Boundary

It was recognised that the area of the cost estimate with the greatest scope for omissions is the balance of plant that must be provided to support the packaged plant. In order to address this, some effort was expended to conceptually design the whole facility and identify all necessary equipment for the base case plant. In addition, a reputable and experienced construction contractor, CBH, was engaged to cost the installation of the plant and all balance-of-plant systems. For the smaller developments, costs were estimated from this detailed work. The conceptual plant layouts were developed by GDY in-house as shown in **Appendix B**.

This section lists the detailed scope of works considered in developing cost estimates for the base plant option.

8.3.5.1 Construction Estimate (including some supply items)

Costs were estimated by CBH (Clyde Babcock Hitachi). The balance of plant design is summarised as follows. Equipment size and weight estimates are a composite of the PHP, Ormat and TAS proposals.

Construction is summarised as follows:

- Clear and grade main plant area of 120 x 90 m.
- Construct adjacent chemical dam of 30 x 30 m, with liner.
- Construct adjacent thermal/overflow dams of 40 x 70 m, with liners.
- Provide 300m of chain link fencing, 1.8 m high.
- Typical industrial area lighting for the main plant area of 120 x 90 m.
- Typical earth grid and lightning protection for the main plant area of 120 x 90 m

- Blue metal surfacing for the main plant area of 120 x 90 m.
- Allowance for storm water diversion.
- Allowance for underground cable trenching and conduit.
- Typical foundations for all equipment.
- Construction of two pipe racks, either side of the heat exchanger farm, each 100 m long and 7 m wide.
- Allowance for 100 bored pier pipe supports, shown in
- Typical foundations for all equipment.
- Transport from Australian port and installation of packaged air coolers
- Transport from Australian port and installation of packaged power plant modules as follows:

Item	Dimensions	Weight
Preheater	17 m x 1m	45 tonne
Evaporator	18m x 1m	55 tonne
Air condenser	35m x 12m (total)	TBA
Turbine/expander skid	4m x 4m	16 tonne
Hot well	3m x 1.2m	4 tonne
Generator	5 x 3m	35 tonne
Feed pumps skid	5m x 2.5m	7 tonne
Lube oil skid	4m x 2m	4 tonne
Hydraulic skid	2m x 1.5m	1 tonne
Vacuum pumps skid	1m x 1m	0.5 tonne
Load bank for island operation	2m x 2m	2 tonne

- Transport from Australian port and installation of ORC fluid storage receiver (19 m x 2.2 m, 25 tonne) and draining pump skid (1.6 m x 1 m and 1 tonne)
- Transport from Australian port and installation of skid mounted intermediate fluid pump skid (1.8 m x 5 m and 10 tonne)
- Transport from Australian port and installation of skid mounted fire pump (1.8 m x 5 m and 2 tonne)
- Supply and install 300,000 L fire water tank (panel tank construction) on road base foundation.
- Supply and install two 20,000 L process/utility water tanks on road base foundation.
- Supply and install 15 m x 8 m store shelter, including some bundage, for storage of oils and chemicals.
- Supply and install 15 m x 8 m building using demountable construction, with allowance for internal fit out into amenity, control room, office, and workshop areas.

- Relocate chemical cleaning skid mounted components from HPP project and construct lined bund for same.
- Buried DN100 fire main and four hydrants
- Supply and install blockwork firewalls for transformer and substation/switchyard (8 m x 8 m x 3 m high)
- Supply and install MCC building as demountable Bondor type building
- Supply of all pipe and fittings.
- Install new and re-used brine reinjection pumps.
- Install one new seal skid and relocate one existing seal skid.
- Supply and install one 10,000 L diesel tank.
- A general allowance was applied by CBH for electrical works. Further electrical conceptual design is required.
- On most items, a 10% contingency should be allowed for costs estimated in this section, due to the likelihood of omissions at this preliminary stage.

8.3.5.2 Equipment Procurement Estimate

- Overhaul of existing two HPS pumps
- Purchase of three new HPS pumps, inclusive of motors and thrust chambers and baseplates.
- Purchase of 1 additional /redundant seal skid
- Purchase of initial complement of pump seals
- Fire suppression system for transformers and MCC
- Supply and connect 500-1000kVA diesel generator
- Allowance for electrical cabling and tray.
- Allowance for instrumentation
- Supply 5 new wellhead ESD valves
- Supply 3 new production well control valves
- Supply 4 new injection check valves
- Supply manual (gate) valves. An initial count suggests 55 valves, however a contingency allowance would be 70 valves. Most valves are in brine service, with design conditions of 360 barg and 260°C. As a coarse indication, the average valve size is DN200.
- On most items, a 10% contingency should be allowed for costs estimated in this section, due to the likelihood of omissions at this preliminary stage.

8.3.6 Heat Exchanger Methodology

A target was set to reduce the cost of the high pressure heat exchanger costs by lowering manufacturing costs and using more cost effective designs. To achieve this, the design package for the HPP exchangers was re-issued to the original supplier (Tenix, in New Zealand) for re-pricing. The package was also issued to two Indian manufacturers (ISGEC and Larsen Toubro), to access lower manufacturing costs.

In addition, significant attempts were made to identify second hand exchangers, being retired from the thermal power or nuclear industries, however the process conditions at Habanero appear to be almost unique and no second hand candidates could be identified.

Suppliers were requested to price the supply of many small heat exchangers manufactured in a production style method, and requested to propose alternate designs, especially larger units (still road transportable) that might exploit standard products or improve surface area/weight ratio. Suppliers were given a functional design basis requiring a heat transfer of 85 MW_{th} with set brine flowrate and temperatures, all other parameters were left to the Suppliers knowledge.

The original New Zealand-based manufacturer (Tenix) was also consulted for current pricing and the per unit cost savings of the Indian units was an impressive ~50%. It is suggested that further cost savings could be made by through a detailed design and cost optimisation study. This should be carried out if the HGP progresses.

Some package plant suppliers also included the high pressure heat exchangers in their scope, as the 'preheater' and 'evaporator' components of their binary power plants. These exchangers were more CAPEX-efficient than the separate small units sourced from India. Given the extreme service conditions, it would be prudent to verify this pricing if the project proceeds further. Ensuring that the plant suppliers have the capability to deliver high pressure heat exchangers at the high quality required will be critical importance when considering such proposals in the future.

In summary, heat exchanger costs from ISGEC in India were used for those plant offers that did not include them, otherwise plant supplier costs were used.

8.3.7 Brine Field Piping Methodology

Cooper Basin EGS brine piping is very expensive due to the large wall thickness required to contain the pressure and the fact that steels must be de-rated for the high temperature (36 MPag at 220°C) and 45 MPa at 50-100°C in the reinjection system. Corrosion allowance must be added and in the HPP Project, wall thicknesses up to 22 mm resulted for DN150 pipe.

In addition, common high strength pipeline materials, such as API 5L Grade X70, that could deliver pressure strength with minimal wall thickness are prohibited under most piping codes at these high temperatures, and if not, they are de-rated to the point where wall thickness becomes too great.

Early investigations looked at GRE (Graphite Reinforced Epoxy) pipe, which failed the temperature criterion by a large margin. Also, glass-lined high-strength steel pipe, which may be suitable for the service but spools longer than 3 m cannot be internally glazed, which made it an unfeasible solution. CRA (Corrosion Resistant Alloy) lined pipes from the subsea oil industry show promise and this could be pursued further.

CBH (Clyde Babcock Hitachi) were commission to carry out a holistic cost optimisation study encompassing materials, fabrication and construction costs to identify the optimum high pressure brine material. CBH are specialists in the power industry and investigated exotic high chromium materials with minimal temperature de-rating, but with some special requirements for welding. The process culminated with a comparison by CBH between DN17175 X20CrMoV12-1, equivalent to EN10216-2 X20CrMoV11-1 material, and ASTM A106 Gr C (the material used for HPP).

CBH identified the X20 material as a candidate and Quest Integrity carried out a preliminary evaluation. The material is a martensitic 9 to 12 % Cr stainless steel alloy with a broad range allowed for alloying elements: C(0.17-0.23%), Cr (10 to 12.5%), Ni (0.3-0.8), Mo(0/8-1.2) and V (0.25-0.35). The steel was designed for use at high temperatures of the order 400 to 500C (and higher) for steam pipe and boiler pipe applications (see for example Skobir et. al. 2008 in Surf. Interface Anal. 40: 513-517).

This steel was used as the basis for developing cost estimates for the HGP. It should be noted that the alloy has not been listed in the ANSI/NACE MR0175/ISO 15156-3:2009€ standard as being suitable for H_2S service and if the project proceeds further, verification of certification for H_2S service should be sought from the supplier, or else laboratory testing undertaken. The corrosion rate of this alloy would not be expected to differ significantly from those in the HPP Project.

Based on results of preliminary corrosion coupon analysis and brine pipe internal inspection from the HPP project, carbon steel materials will be designed and priced assuming a corrosion allowance of 3 mm, based on a design corrosion rate (for pitting and general corrosion) of 0.2 mm/yr.

Cost estimates were finalised based on the use of this material, due to its 40-50% reduction in wall thickness relative to A106C. However at the end of the study, there were some unresolved questions about the material.

Despite constant approaches, no supplier could actually quote the cost of the material in the pipe diameters and thicknesses required. The material is known to be expensive, and in the end, a cost of 200% of that for A106Gr C was used. This virtually cancels the cost saving due to reduced wall thickness, but at least means that if the material proves unviable, then an alternative design based on A106C would have approximately the same cost.

8.3.8 Process Heat Water Pipeline Methodology

There was a large uncertainty in the cost of a process heat pipeline during preliminary investigations; therefore, GDY engaged a reputable consultant, SKM, to carry out a desktop study and budgetary cost estimate. This estimate was benchmarked against industry standard rates and rule of thumb cost estimates.

8.3.9 Electrical Transmission Methodology

GDY approached Cowell Electric, who have designed, installed and operated power lines in the Cooper Basin and who constructed the (unused) line from the HPP project to Innamincka township. Cowell were asked to provide concept design and costing for a 66 kV line (with optional consideration of 33 kV) and also to advise on the ultimate availability of power lines in this region with respect to outages due to storms, third party interference and other causes.

Cowell were provided with an indicative 70 km route to Moomba, which included two offtakes of lower voltage (see **Figure 8-27**). The offtakes are intended for smaller loads that have high electricity generation costs from diesel generators, and are designed to be relocatable in recognition of the fact that small diesel loads, such as temporary camps or well pumping stations, may only be present for short periods of time, say ~3 years. The line was rated to 10 MW_e with a 0.85 power factor. A cost estimate was prepared by Cowell Electric for this infrastructure.

Given Cowell's direct experience in the Cooper Basin region, transmission cost estimates can be considered to be quite accurate. The estimate includes the step-up transformer at the power station but excludes the step-down unit at Moomba.

Figure 8-26: Showing 33kV Construction in a Region Similar to the Cooper Basin.

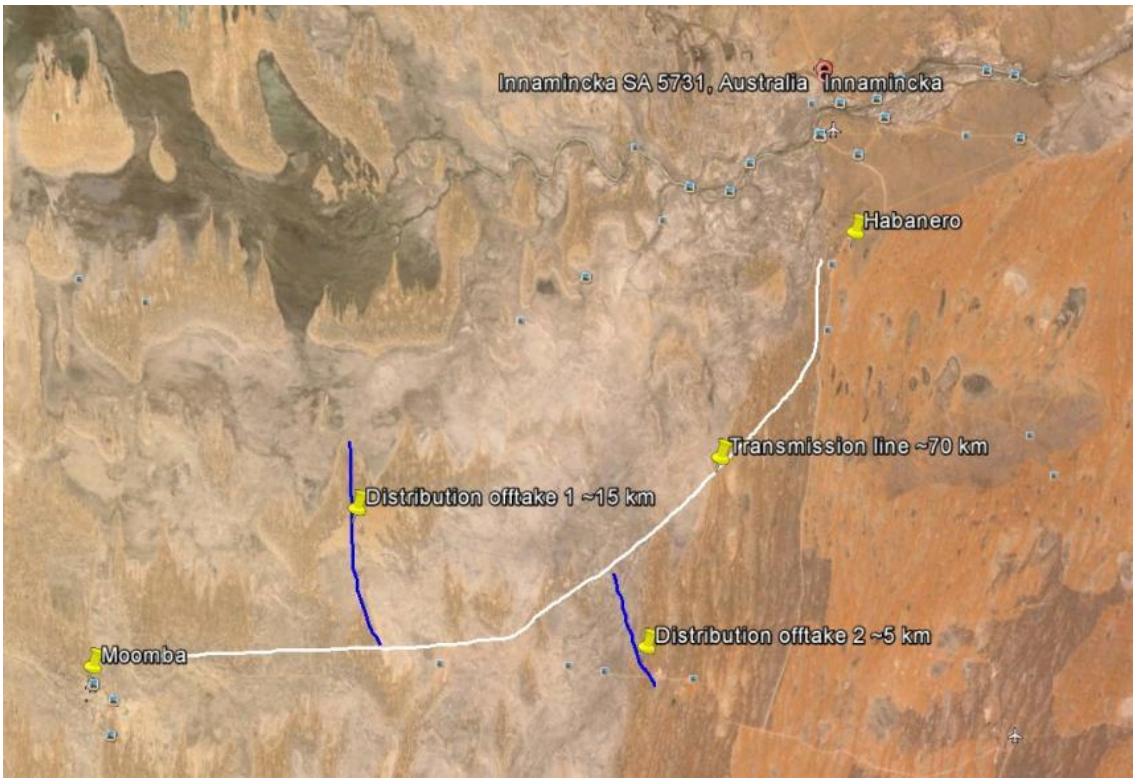


Figure 8-27: Proposed Route for Electrical Transmission (and Hot Water Pipeline)

8.4 The Base Project - Six Wells Power

The concept of the "base project" is to supply a nominal 7.5 MW_e (state actual number) to either the existing Santos Moomba gas plant or a similar new plant, located closer to the Habanero resource, developed by another gas industry proponent. As explained above, the actual net power available for transmission is more like 6-7 MW_e, based on the offers received.

This is a six-well project, consisting of five new wells and the re-use of Habanero 4. Habanero 4 will be used as an injector, leaving three new production wells and two new injection wells to be drilled. Habanero 1 is not included in this project. The well field layout is shown in **Figure 8-28**.

The brine system will be predominately new, but will integrate the existing pipeline and valves to Habanero 4. The pipeline will be constructed with shop fabrication maximised to minimise on site construction, and insulated to prevent temperature losses. Common runs of pipe are manifolded as shown in the diagram below. Piping is run alongside existing roads to simplify construction and minimise environmental impacts.

Transmission consists of a ~70 km 66 kV transmission line direct to Moomba, with lower voltage offtakes for smaller loads along the route (refer to **Figure 8-27**), or a short transmission run to a nearby gas processing plant in the future. Transmission is discussed in greater detail in **Section 8.3.9**.

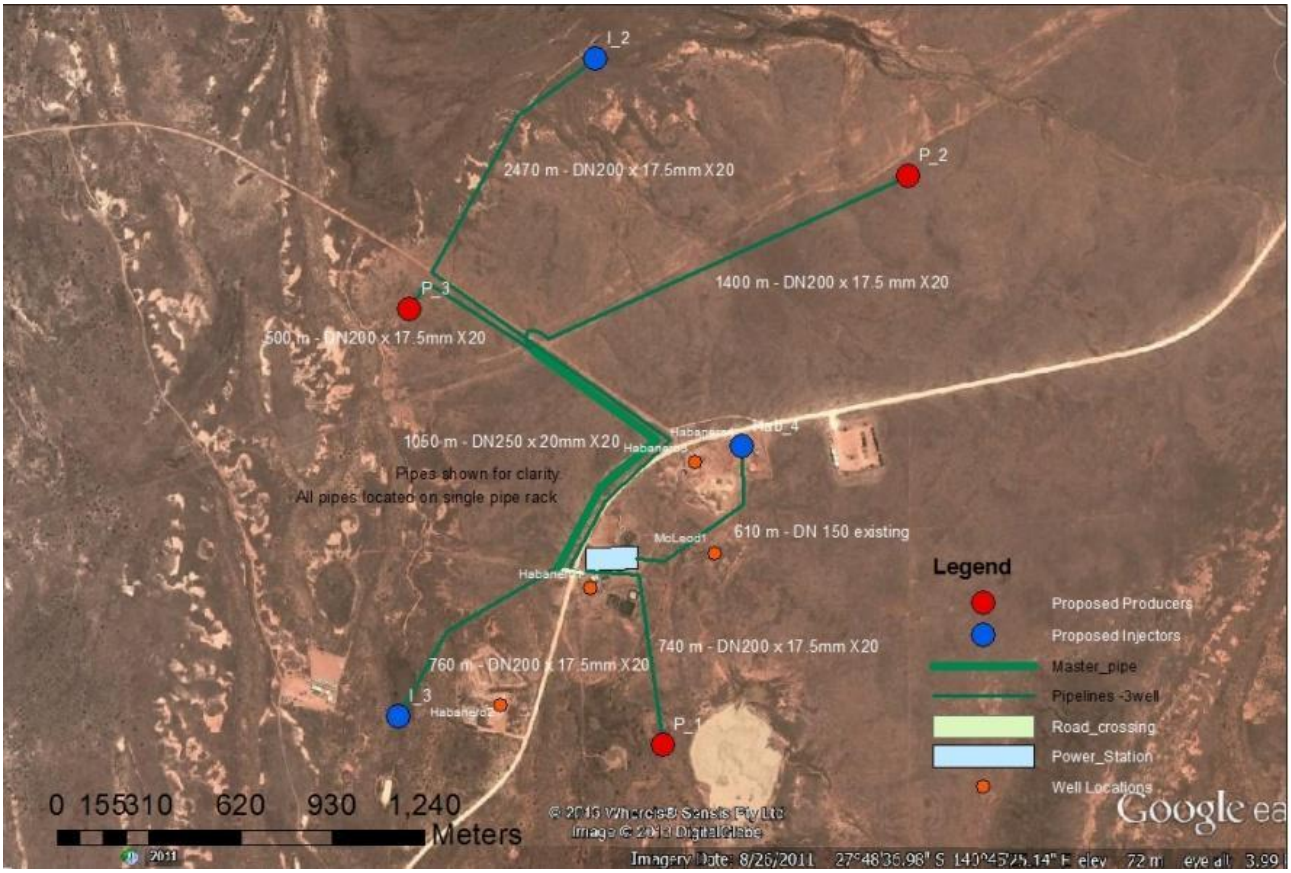


Figure 8-28: Field layout for 6 well development

Figure 8-29: Typical Dual unit ORC (8 MWe plant installed in Hawaii, Puna Expansion, 2011)

8.4.1 Capital Costs

The plant is expected to generate an average ~7 MW_e at a net thermal efficiency of ~11%, and a net utilisation efficiency of ~29%. The plant has relatively poor net output due to the large auxiliary loads of the plant itself and the brine reinjection pumps. This combined with the high capital costs gives a relatively very high specific net CAPEX of ~$9 million/$MW_e$.

8.5 Alternative Project - Six Well Heat

The concept of the process heat project is to supply ~60 MW_{th}, in the form of hot water, to either the existing Santos Moomba gas plant or a similar new plant, located closer to the Habanero resource, developed by another gas industry proponent.

For the heat supply option to Moomba, the concept involves exchanging heat from the brine to a low pressure water pipeline, which is then pumped via insulated pipeline to Moomba and returned via a second (uninsulated) pipeline. Any costs associated with distribution and integration of heat within the customer's plant are excluded from this study.

The well field layout and brine system is the same as for the base project.

The majority of performance and cost estimates have been taken from the work carried out for the base six-well power project for brine piping, heat exchangers, and pumps; a pipeline cost estimate by SKM; and in-house work for energy balances and cost estimations for balance of plant items.

Key parameters are:

- Delivered temperature of 170-220°C (170°C to Moomba, and 220°C to a co-located facility)
- 60 MW_{th} of heat (could be between 30 -90 MW_{th} depending on customers' requirements)
- Six EGS wells, re-using Habanero 4, thus two new producer wells and three new injector wells.
- Extensive augmentation of existing brine heat exchangers and reinjection pump

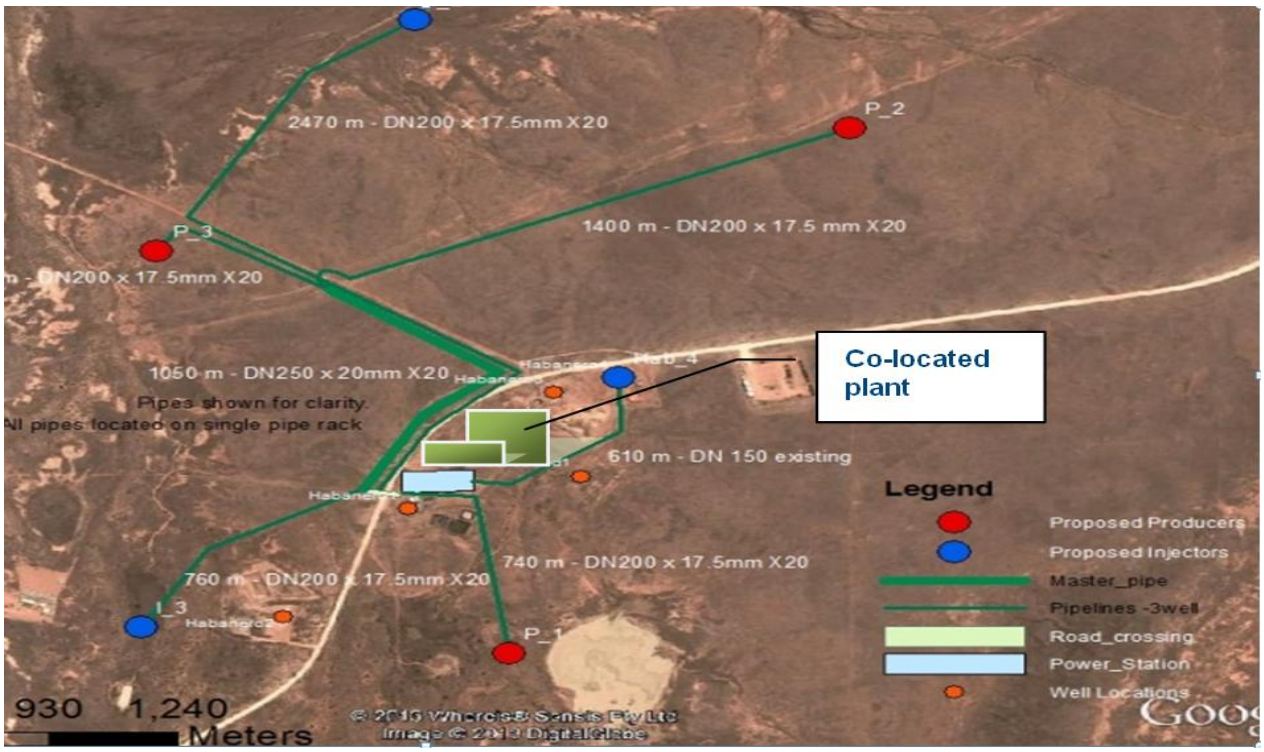


Figure 8-30: Field layout for 6 well process heat development, assuming co-located customer

8.5.1 Concepts Investigated

Two concepts were investigated:

- Supply of process heat via an intermediate hot water circuit and overland pipeline to the existing Santos Moomba gas plant. However, this option has significantly higher capital costs and temperature losses compared to a co-located user.
- Supply of process heat to a co-located plant in a six well development. This option assumes that the geothermal fluid is used in the gas plant and that there is no intermediate water loop as efficient integration is assumed.

The scope of works for the supply of process heat:

- Procurement and installation of an array of new brine heat exchangers in parallel with the existing heat exchangers.
- High pressure brine piping and associated valving to connect the new wells.
- Additional high pressure valve to allow double isolation for redundant equipment maintenance to increase reliability.
- Upgrade brine reinjection pump system to an N+1 configuration.
- Vessels, low pressure piping, and associated pumps for the intermediate low pressure circuit circulating.
- Insulated above ground return pipeline line with piled supports to Moomba.
- Procurement and installation of a high efficiency diesel or gas fired generator in combined heat and power configuration to power pumps and reduce fuel costs.

The scope of works for the integration of geothermal heat with a co-located plant is the same as above, except that:

- Pipeline costs have been excluded.
- Power for the brine reinjection pumps is provided by the gas plant at a cost of ~$100/MWh.

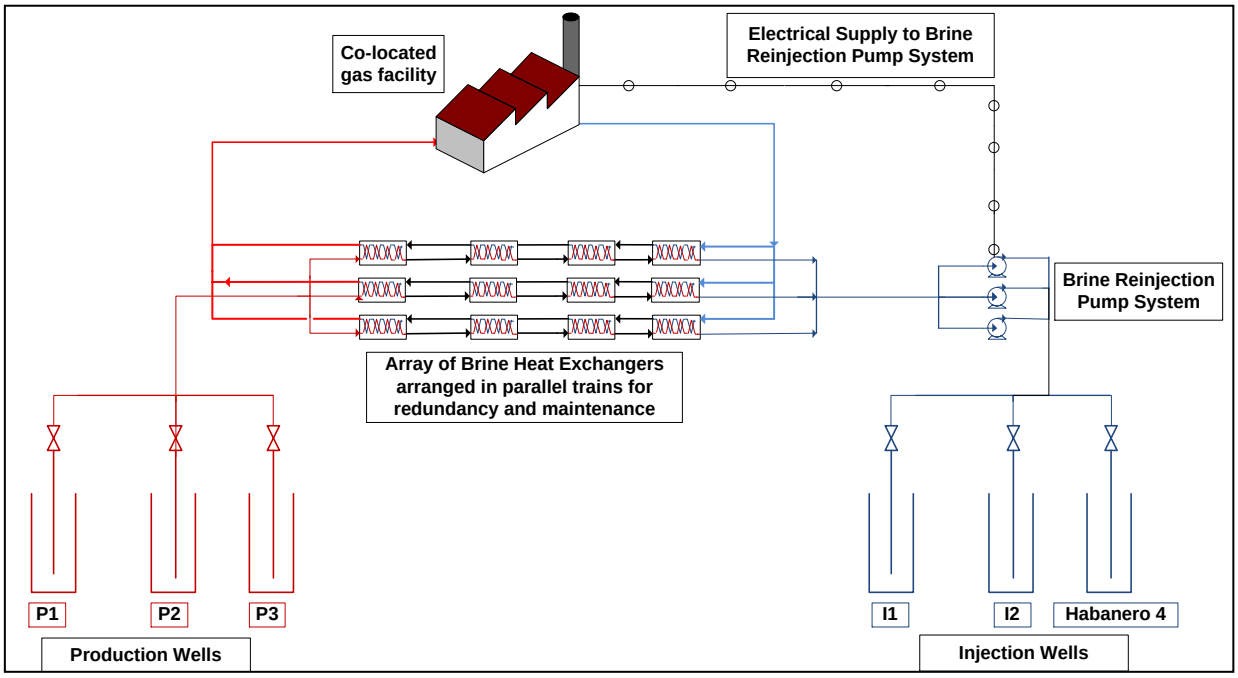


Figure 8-31: Schematic of process heat supply to a co-located consumer

8.5.2 Capital Costs

It was estimated that the plant CAPEX required to supply process heat directly to a local consumer would be about $40 million. Estimates of the additional CAPEX required for transmission by pipeline for any significant distance were too large to consider this option any further.

8.6 Alternative Project - Four Wells Power

This option involves supplying approximately 3-5 MW_e of electricity via overhead wires to Santos Moomba gas plant, or other major load, with supply routed via one or more smaller loads such as a permanent camp or township in the Cooper Basin.

The intent of this option was to investigate whether the significant reuse of existing equipment would significantly impact the economics. The majority of cost estimates are taken from unit pricing revealed in the base six-well project, a budgetary price for a refurbished turbine from GDA, local supplier quotes for air cooled condensers, power plant design and costing software, and in-house data. It should be noted that the costs and performance for this option will not be as accurate as the six-well project because the concept design and costing methodology is not as specific and detailed.

The reason for selecting the four well scenario to investigate the benefit of saving CAPEX by reusing the maximum amount of existing equipment is that the size of the existing equipment starts to become significant. For example, the existing turbine can potentially produce ~50% of the power and the existing brine heat exchangers can contribute ~15% of the required heat duty. Further, Habanero 4 can supply 50% of the required heat.

The basic assumptions detailed in the base project were also used for the four-well project, except that the brine flow was increased to 80 kg/s based on the assumption of including Habanero 1.

The key guiding parameters were:

- Approximately 5 MW_e of electricity
- Four EGS wells (including Habanero 4)
- Modest augmentation of existing brine heat exchangers and reinjection pump
- Opportunity to utilise the existing 1 MW Plant, in an overall solution that is not particularly thermally efficient, but is low CAPEX.

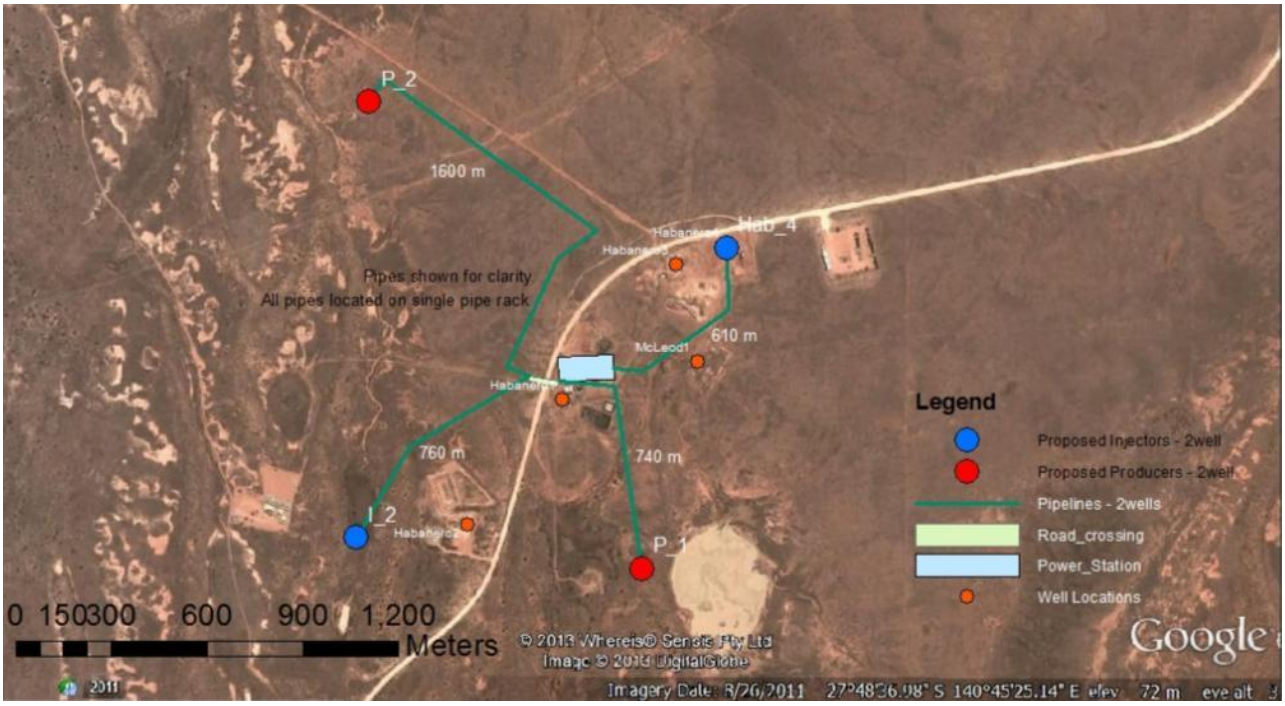


Figure 8-32: Field layout - four well development

8.6.1 Concepts investigated

Two concepts were investigated:

- A dual flash plant using the existing steam turbine in a high pressure cycle, and a refurbished turbine as in a low pressure cycle, with a new air cooled condenser (**Figure 8-33**).
- A dual cycle plant that uses the existing turbine in a single pressure flash configuration combined with a new ORC plant used as a bottoming cycle (**Figure 8-34**).

These options were benchmarked against the third option of a new plant cost and performance estimates to gauge whether the brownfield project had significant savings over a greenfield option. Such a brownfield project must have significant benefits over greenfield option because there is inherently more complexity and risk. Also, and importantly, performance risk in a brownfield development would most likely need to be carried by GDY.

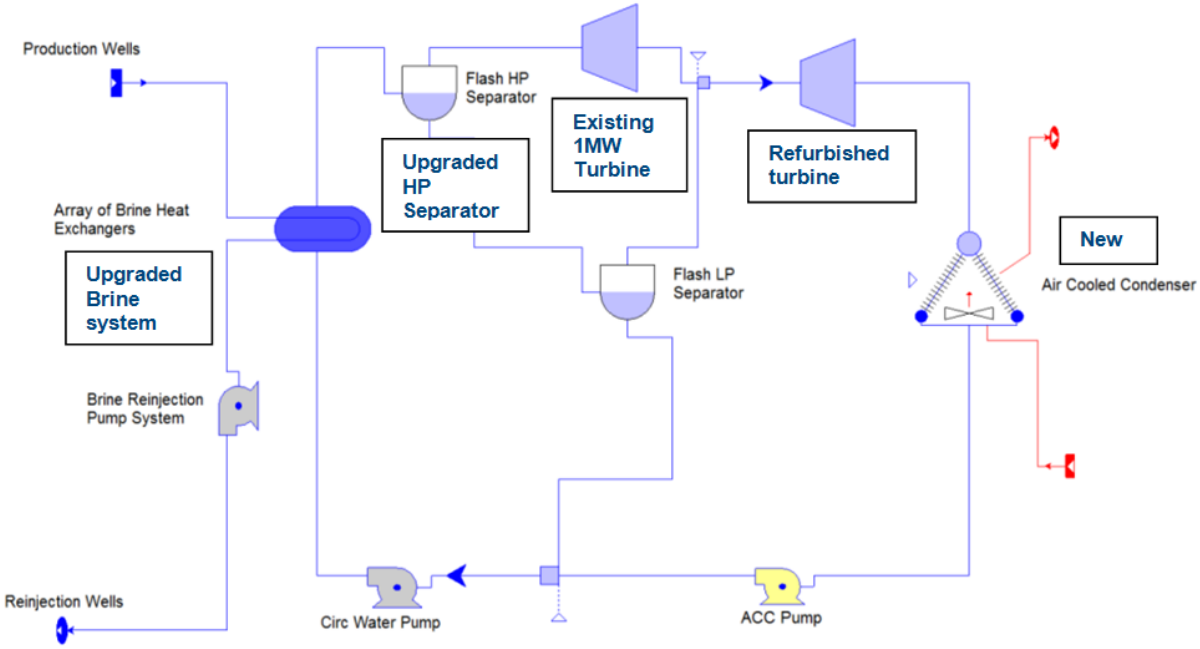


Figure 8-33: Process schematic of dual flash plant incorporating existing 1 MW plant

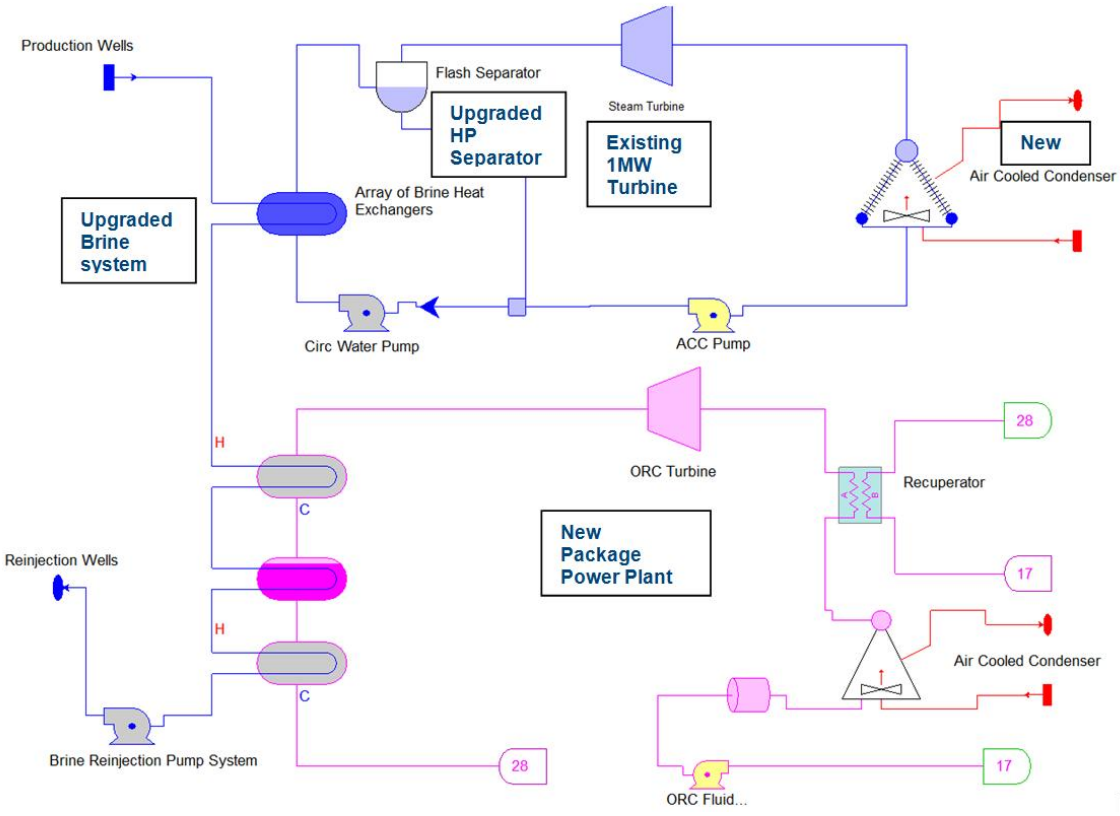


Figure 8-34: Process schematic of dual cycle plant incorporating existing 1 MW plant

8.6.2 Capital costs

Upgrading the 1 MW plant to a dual flash system with a second hand turbine was expected to be of significantly lower CAPEX than the other options. However, there are no capital savings because buying individual pieces of equipment leads to high costs, and the plant equipment represents a

relatively small portion of the overall plant costs, ~35%. The brine system, project management and other costs comprise a significant portion of total costs, which are similar for all options.

Upgrading the 1MW plant and installing a bottoming ORC cycle has the lowest CAPEX out of the options, $38.4 million, but with only a $2 million saving it would be hard to justify the risk associated in choosing this brownfield option over a new packaged power plant.

It was difficult to find construction cost savings for the brownfield projects as they have a much higher on-site component that leads to higher construction costs, and the small and remote nature of the project makes it difficult to realise construction cost savings by reducing scope. There is also increased risk of construction cost and schedule blow-out in brownfield projects.

8.6.3 Performance summary and comparison

Table 8-6 shows a performance summary and comparison of the options, and reveals the following conclusions:

- The integration of existing plant equipment, in particular the turbine, leads to a plant with significantly lower performance due to the un-optimised cycle, demonstrated by the lower power performance of ~30%.
- The capital savings made by the brownfield project are minimal, and cannot be justified because of their low net power output, which negatively affects the project specific CAPEX and will adversely affect project economics.

In summary, it is difficult to justify the reuse of the existing plant given the poor performance, high specific CAPEX, additional complexity involved in a brownfield project, and the inability to secure performance guarantees from a plant supplier to mitigate performance risks.

With regard to a four well development a new ORC based packaged plant is recommended, and is estimated to cost ~$40 million plus transmission costs.

Table 8-6: Summary table of performance and cost - four well project

Description	Units	1 MW upgrade to Dual Flash	1 MW upgrade to Dual Cycle	New Ormat ORC
Gross Power	MW	5.5	5.6	6.9
Net Power	**MW**	**3.4**	**3.3**	**4.7**
Total Plant+Drilling CAPEX	AUDm	$94.2	$90.2	$92.2
CAPEX savings from new	%	-2.2%	2.1%	-
Specific net CAPEX	**AUD/kW**	**$27,701**	**$27,344**	**$19,612**
Specific net CAPEX savings	%	-41.2%	-39.4%	-

8.7 Alternative Project - Two Wells Power

This project concept involves supplying approximately 1-3 MW_e of electricity to a closer Santos facility such as a satellite station, or a future closer facility, or a co-located camp, or one or more smaller loads such as a co-located camp and the KJM logistics camp, or a combination of any of these.

The intent was to investigate whether a development with minimal CAPEX could provide a reasonable amount of power at a reasonable cost while making use of existing infrastructure as much as possible. Two alternate field developments were considered: drilling a new production well and utilising both Habanero 4 and 1 as injection wells with brine flow of 40 kg/s, and drilling no wells and utilising the existing Habanero 4 and 1 doublet with a brine flow of 19 kg/s.

Given its small nature, this project may be suitable for research and development where long term testing of the Habanero resource could be carried out, potentially in conjunction with the demonstration of an advanced supercritical power cycle.

The majority of cost estimates are taken from the base project unit pricing, discussion with plant suppliers, local supplier quotes for air cooled condensers, power plant design and costing software, review of reference projects, and in-house data. It should be noted that the costs and performance for this option have a lower accuracy than both six-well and four-well options because the concept design and costing methodology not as specific and detailed. QGECE assisted with the conceptual development of an optimised supercritical ORC cycle.

The key guiding parameters were:

- Approximately 1-3 MW_e of electricity
- Two - three EGS wells (including both Habanero 4 and Habanero 1)
- Maximum reuse of existing wells, brine system and infrastructure
- Electricity supplied to a smaller closer load/s at low voltage, ~11 kV

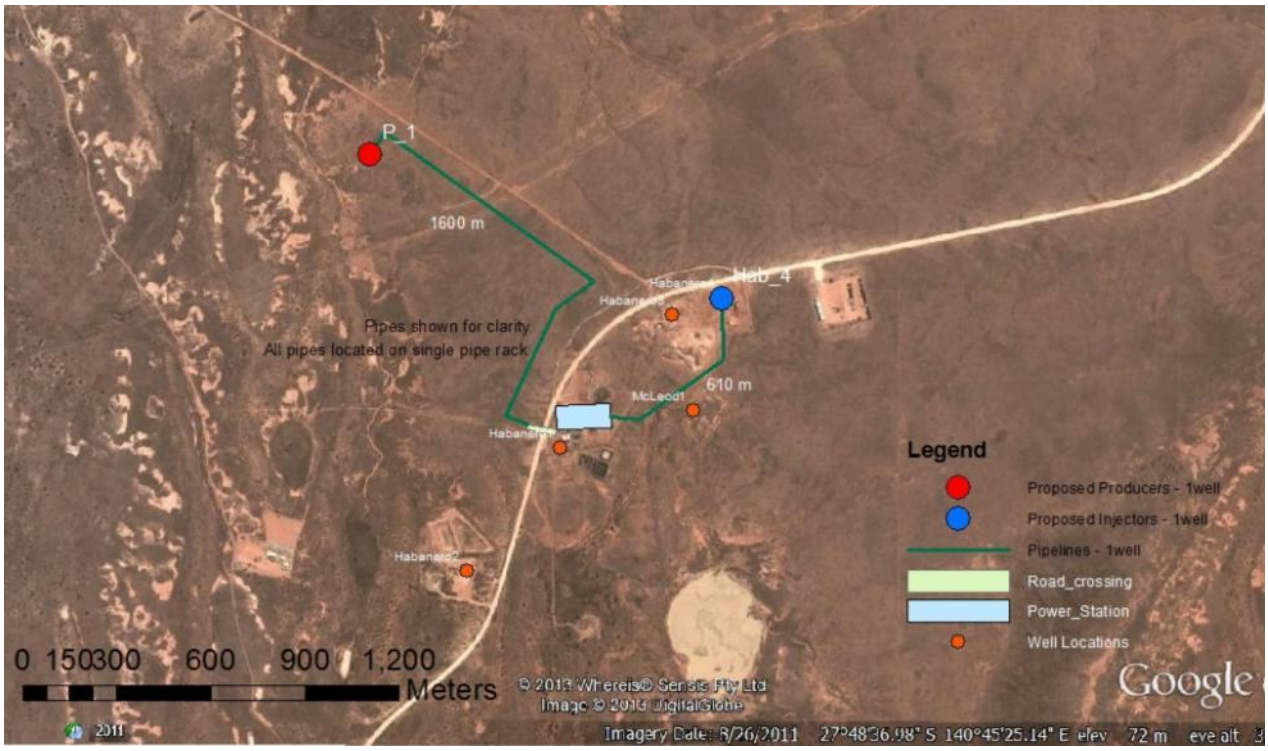


Figure 8-35: Field layout - two well development including one new well

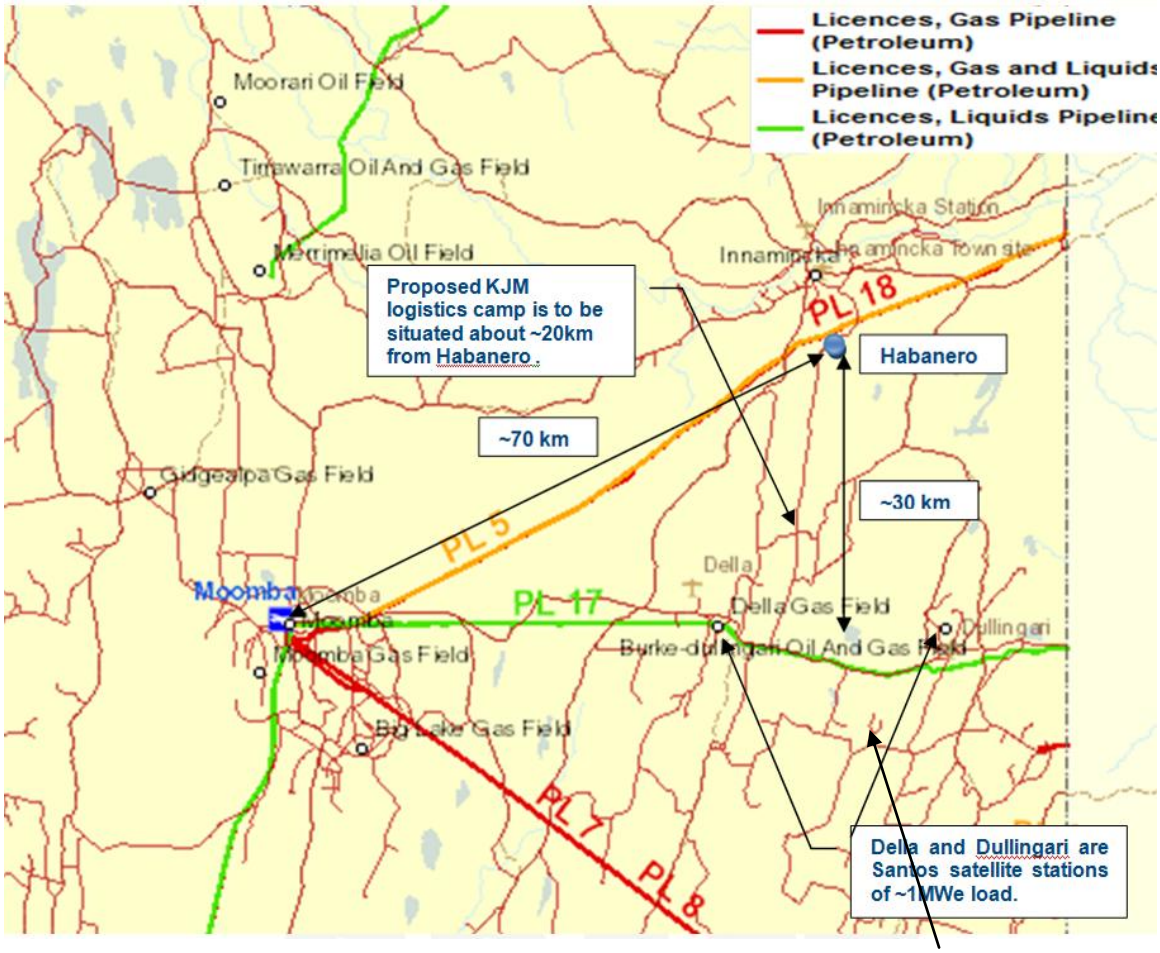


Figure 8-36: Potential customers for a two well project

8.7.1 Concepts Investigated

Three concepts were investigated:

- A single flash plant using the existing 1 MW plant as is with the addition of a second bank of heat exchangers, doubling the capacity of the circulating water system and augmentation of the brine system, connected to one new production well and the two existing wells as injection wells.
- A new high efficiency supercritical ORC based plant of ~3 MW_e net with the one new production well and the two existing wells as injection wells.
- A new high efficiency supercritical ORC based plant of ~1.3 MW_e net with only the existing wells that utilises the existing brine heat exchangers and ties in to the existing low pressure circulating water system. Habanero 4 would be the production well and Habanero 1 the injection well.
- The concept design of upgrading of the existing 1MW plant was done in-house using Thermoflow, costs from equipment previously bought for the original 1MW plant, and up to date pricing for brine heat exchangers and brine piping. The scope of works for the upgrading the 1MW plant includes:
  - Procurement and installation of a bank of four new brine heat exchangers in parallel with the existing heat exchangers.
  - Procurement and installation of a new brine cooler in parallel with the existing brine cooler to cool the brine sufficiently for equipment limitations of the brine reinjection pumps.

- Procurement and installation of a new fin fan coolers and associated equipment to increase the capacity of the cooling system.
- Construction of low voltage transmission line and switchyard.
- Upgrade brine reinjection pump system to a 2+1 configuration.
- High pressure brine piping and associated valving to connect the new well to the existing piping, and additional high pressure valve to allow double isolation for redundant equipment maintenance to increase reliability.
- Vessels, low pressure piping, and associated pumps and valves to increase capacity of circulating water and de-aeration system.

The conceptual design of the supercritical plant comes with less performance and cost certainty. The reason for this is that a proposal for such a plant was not able to be obtained in the time frame available, and it may require that the plant be custom designed and the necessary equipment specified and purchased from individual suppliers. The cost and effort for this detailed work could not be justified at this stage. The scope of works for a new supercritical ORC plant is assumed to include:

- Detailed engineering that would be more substantial than required for a proven plant cycle.
- Procurement of packaged power plant, or individual procurement of key equipment such as turbine, brine heat exchangers and cooling system, and balance of plant.
- Remainder as previously mentioned.

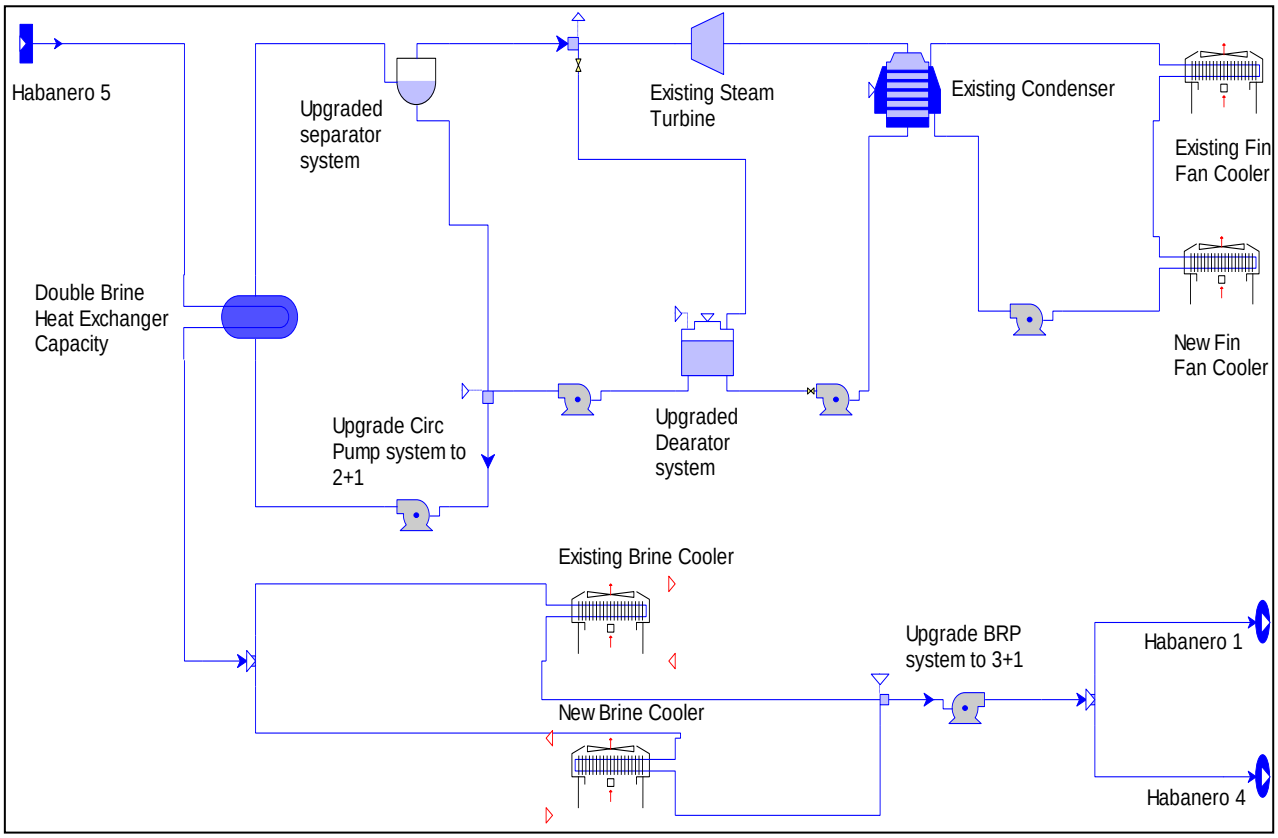


Figure 8-37: Process schematic of upgraded 1MW power plant

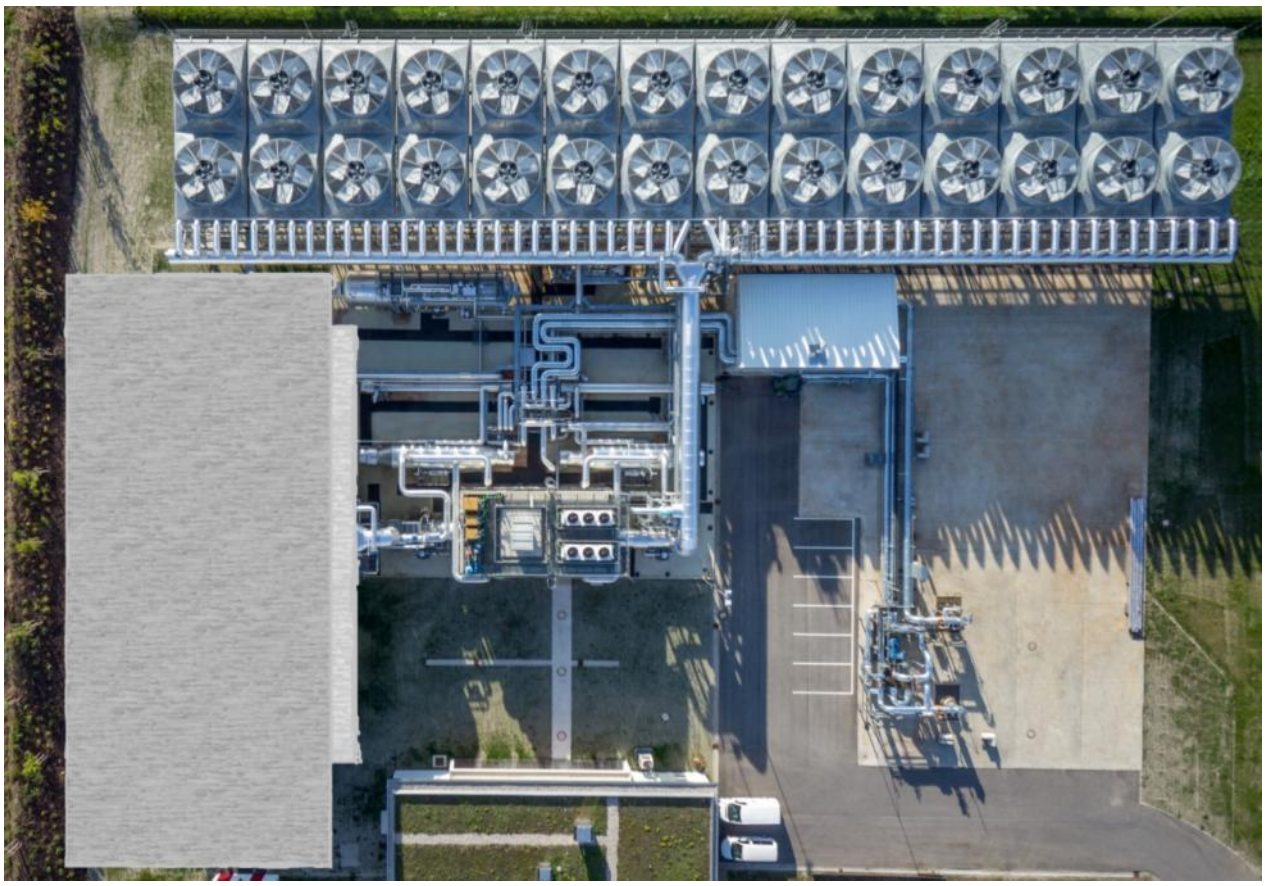


Figure 8-38: Indicative layout of supercritical ORC plant (Indicative footprint 60 x 40m)

8.7.2 Capital Costs

A simple upgrade of the 1 MW plant would cost ~$12 million compared to ~$28 million for a larger new supercritical ORC plant, and ~$13 million for a smaller new ORC plant.

With regard to the 1MW upgrade, the costs are dominated by the brine system and project management and other costs. The costs of the new plants are dominated by the procurement and installation of the plant; however, the smaller plant does have a significant portion of project management and other costs.

8.7.3 Performance summary and comparison

Table 8-7 shows that the supercritical plant is far superior to the upgraded 1MW plant. The poor thermal and utilisation efficiency of the single flash steam based plant is abundantly clear in this comparison, with the large supercritical ORC plant generating three to five times as much net power. Importantly, a new small supercritical plant utilising only ~50% of the heat input could generate up to ~100% more net power than an upgraded 1MW plant.

The small supercritical plant option has the lowest specific net CAPEX by a considerable margin, ~30% better than the larger supercritical plant option, and ~80% better than the upgraded 1MW option. The large supercritical option has over three times the capital efficiency of the 1MW plant when the cost of drilling is included.

The investigation revealed the following key conclusions:

- Using a new small supercritical plant a reasonable amount of net power can be generated from the existing wells, 1-1.5 MW_e net. This is sufficient to supply a co-located plant plus the KJM logistics camp, or nearby small gas satellite station.
- Utilising supercritical technology with one new well can generate a significant amount of net power, 2.5-3.5 MW net. This would be sufficient to supply two small gas satellite stations such as Della and Dullungari, plus a co-located camp.
- Upgrading the 1MW plant to handle higher brine flow from one new well can generate ~700 kW_e, but it with a new well it will cost more than double the small supercritical option for much less net power.
- Transmission costs for any significant distance become relatively very high for such small projects

With regard to the two well development scenario, a new supercritical ORC plant is recommended. The exception would be if it was desired to drill a new well for research and development purposes and no power export was necessary. In this case no upgrade to the 1MW plant would be required for it to cover all plant loads and a co-located camp of ~150 kW_e.

Table 8-7: Summary table of performance and cost - two well project

Description	Units	1MW upgrade	Supercritical ORC (H5-H4&H1)	Supercritical ORC (H4-H1)
Gross Power	MW	2.1	3.8 - 4.8	1.5 - 2.2
Net Power	MW	0.7	2.5 - 3.5	1.0 - 1.5
Thermal efficiency (net)	%	5.4%	~15%	~14%
Utilisation efficiency (net)	%	8.9%	~37%	~31%
Total Plant+Drilling CAPEX	**AUDm**	**$35.0 m**	**$47.4 m**	**$13.3 m**
Specific net CAPEX	**AUD/kW**	**$49,961**	**$15,803**	**$10,640**

9. ENVIRONMENTAL AND SOCIAL ASPECTS

GDY has operated in a sound manner with regard to environmental and social aspects of EGS projects in the Cooper Basin for ~10 years. As such, GDY has significant experience, tools, practices and policies to facilitate this for future projects. The details of which will not be repeated here, instead the following existing documents are referenced, and can be made available on request. A specific Environmental and Social Impact Assessment (ESIA) should be carried out to cover any project specific details not already covered in the below documents at a later stage in the project.

- ENV-FN-EX-GDE-00728 Operation of 1MW Geothermal Power Plant at Innamincka SEO
- ENV-FN-EX-RPT-00794 EIR 1MW Power Plant - 5 Year Review by Wolf Peak Pty Ltd
- ENV-FN-EX-GDE-00721 SEO for Airborne Geophysical Operations in South Australia
- ENV-FN-EX-GDE-00722 SEO for Ground Based Geophysical Operations Non Seismic
- ENV-SY-OT-GDE-00512 SEO Enhanced Geothermal Systems Reservoir Stimulation and Evaluation
- C0115-PLA-005-1.0 Habanero Pilot Plant Project Environment and Approvals Management Plan
- Habanero Environmental Control Plan (See **Figure 9-1**)

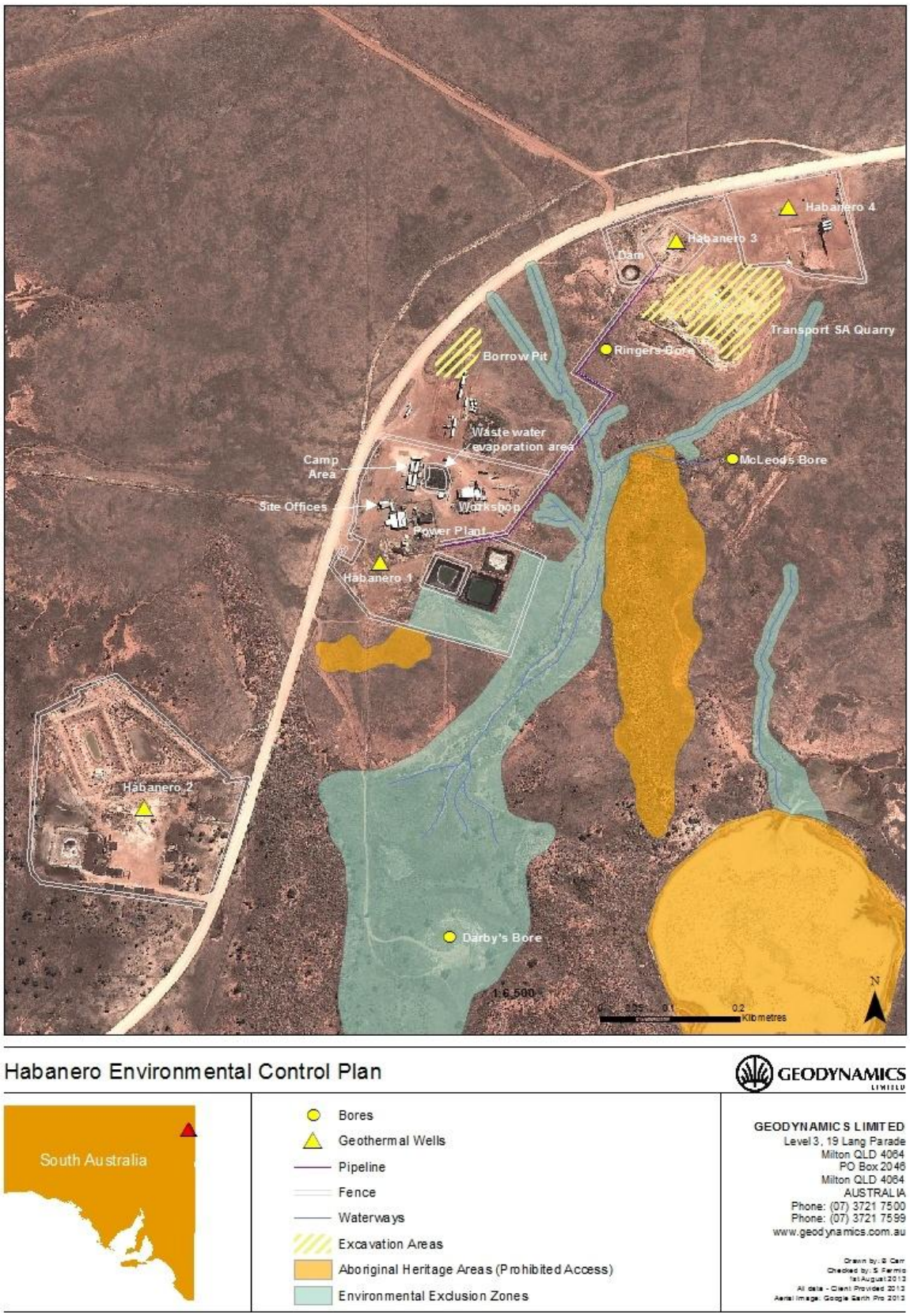


Figure 9-1: Habanero Environmental Control Plan

10. CAPITAL COSTS

This section presents and discusses the estimated capital costs of the main projects considered.

10.1 Overall Project Capital Costs

The capital costs of the projects considered are compared in **Table 10-1**.

For the base electrical project, it is estimated that it would cost ~$180 million, including contingency, to supply ~7 MW_e net to the Moomba gas facility. For a more local user with minimum transmission requirements, the total cost is estimated to be ~$160 million.

The base direct heat project is estimated to cost ~$135 million, including contingency, at the inlet and outlet tie-in points of a co-located plant. This cost could be optimised further in the design phase of a new plant.

With regard to the alternate projects, the specific CAPEX numbers provide a good indication of their relative attractiveness compared to the base project (see **Table 10-1**). An alternate four well project has very similar specific CAPEX to the base project, indicating little capital efficiency gains from decreasing the number of new wells from five to three. Considering the higher specific operating cost of a smaller development, this alternate option is unlikely to provide better performance than the base project. However, this project might be appropriate given smaller loads, capital limitations, or other.

The smaller alternate projects of 3 MW_e and 1 MW_e provide much lower specific CAPEX numbers at the generator output terminals, by as much as ~50%, due to the low number of new wells required. However, transmission costs increase the specific CAPEX by a relatively larger amount, and the improvement is limited to ~25% when transmission is included. The specific CAPEX numbers provide strong evidence that minimising transmission distance, and therefore costs, will have significant positive effect on project economics.

Table 10-1: Overall project capital cost estimate (Australian Dollars)

Description	Base project - 6 wells electrical	Alternate project - 6 wells heat	Alternate project - 4 wells +H01	Alternate project - H05/H04/H01	Alternate project - H04/H01
Performance					
New wells	5	5	3	1	0
Total wells	6	6	5	3	2
Net Power/Heat	7 MW_e	60 MW_{th}	4.7 MW_e	3.0 MW_e	1.3 MW_e
Capital costs					
Wells	$82.2m	$82.2m	$51.8m	$22.7m	$0.0m
Plant	$23.4m	$1.8m	$14.0m	$11.0m	$4.0m
Brine System	$30.2m	$29.0m	$17.5m	$10.0m	$6.0m
PMgmt&Other	$9.9m	$9.4m	$8.9m	$3.7m	$3.3m
Total - Generator terminals	**$145.7m**	**$122.4m**	**$92.2m**	**$47.4m**	**$13.3m**
Transmission	$19.8m	$0.0m	$14.0m	$9.0m	$9.0m
Total - Customer terminals	**$165.5m**	**$122.4m**	**$106.2m**	**$56.4m**	**$22.3m**
Contingency (10%)	$16.5m	$12.2m	$10.9m	$5.6m	$2.2m
Total inc Contingency	**$182m**	**$134.6m**	**$117.1m**	**$62.0m**	**$24.6m**
Specific cost comparison					
Specific CAPEX - Wells+Plant	**$20.8/$MW_e$**	**$2.0/$MW_{th}$**	**$19.6/$MW_e$**	**$15.8/$MW_e$**	**$10.2/$MW_e$**
Specific CAPEX - Wells+Plant+Transmission	**$23.6/$MW_e$**	**$2.0/$MW_{th}$**	**$22.6/$MW_e$**	**$18.8/$MW_e$**	**$17.2/$MW_e$**

10.2 Capital Cost Analysis of Base Project

The capital cost breakdown of the base project is presented in **Figure 10-1** excluding transmission and contingency. This graph clearly shows that wells are the dominant contributor to capital costs, and that the brine system adds significant CAPEX due to the extreme process conditions.

Figure 10-2 compares the estimated Habanero development costs to global geothermal benchmarks from various sources. This graph shows that EGS is significantly more expensive than conventional geothermal; EGS at Habanero is significantly more expensive again due to the extreme process conditions, depth of reservoir, and remote location; and drilling of the wells at Habanero alone is more expensive than most geothermal projects in their entirety.

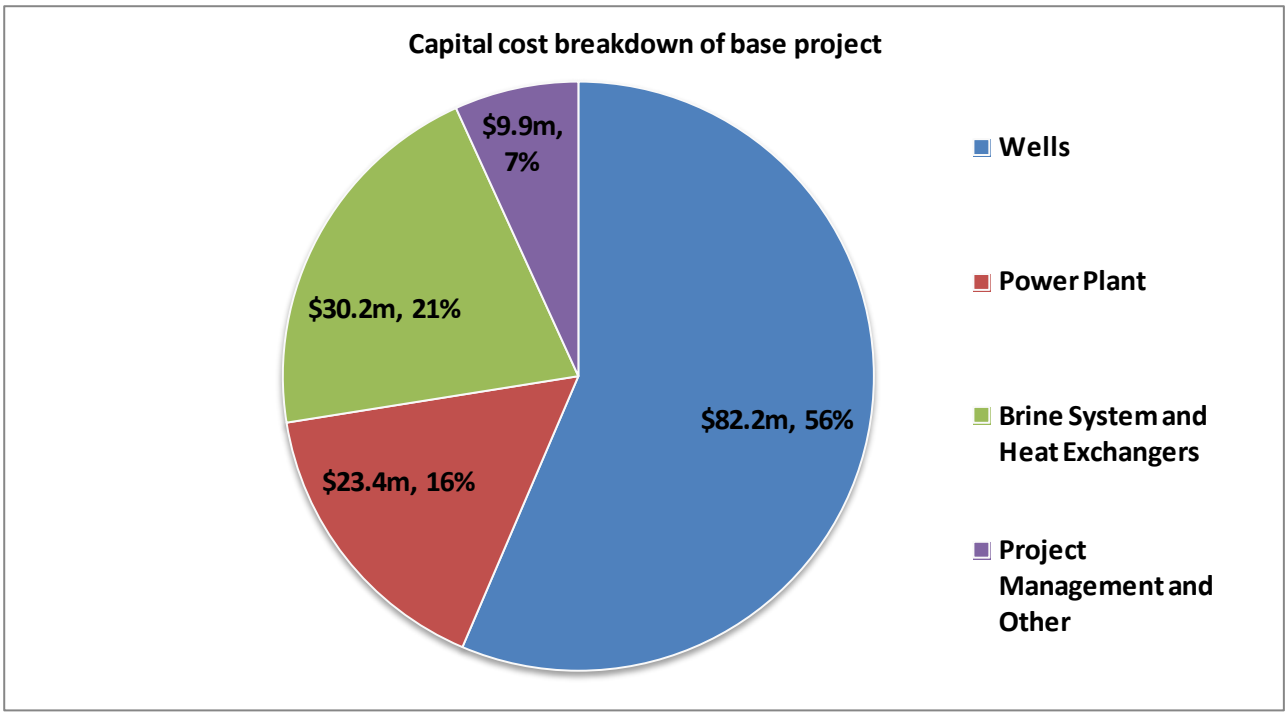


Figure 10-1: Capital cost breakdown of base project

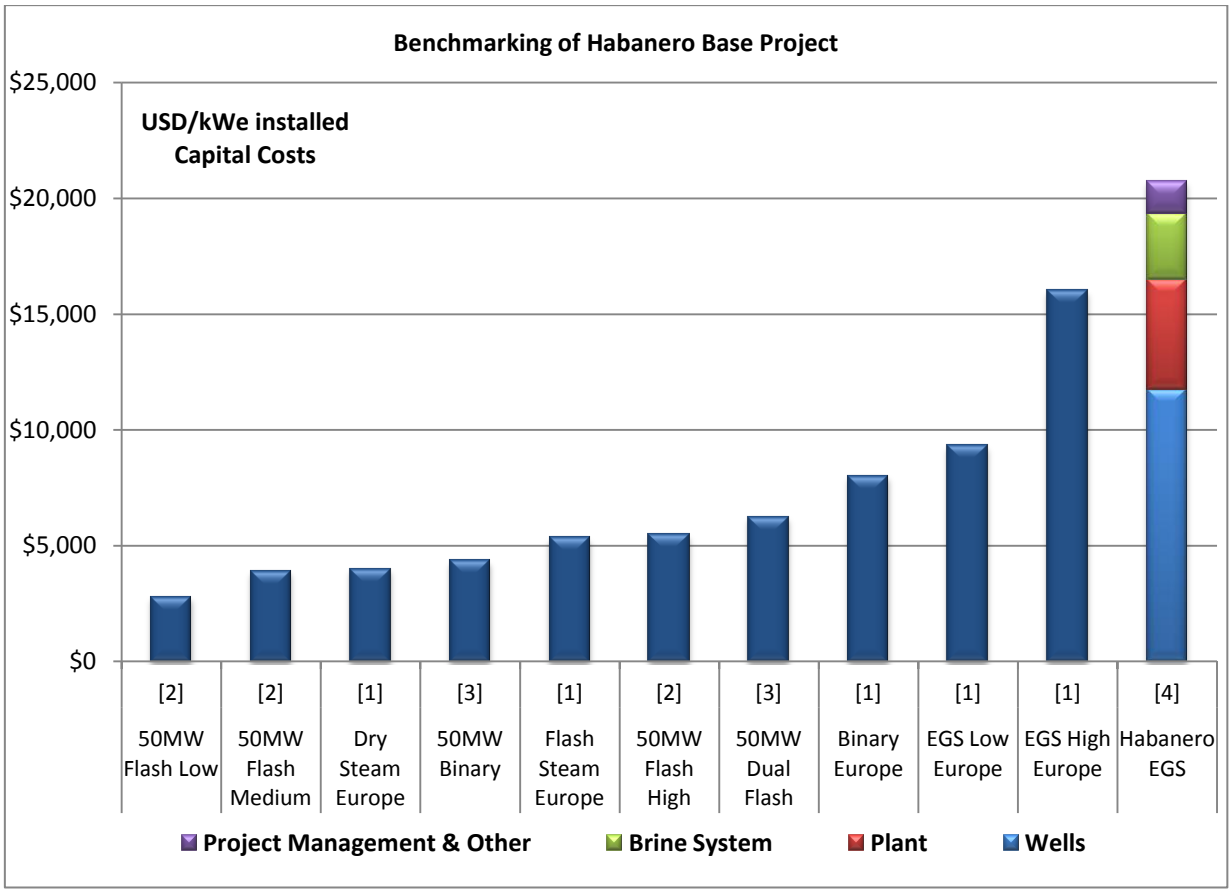
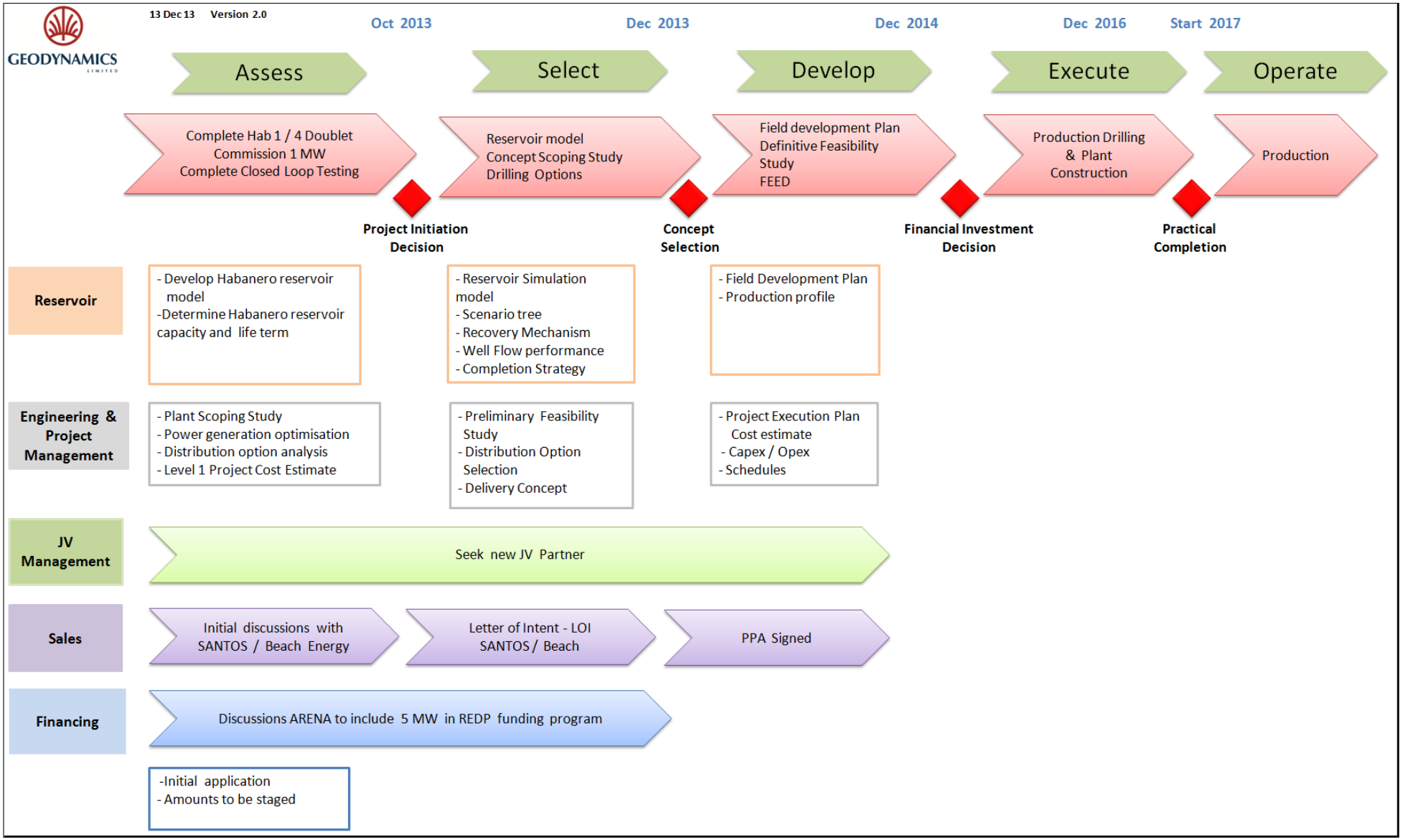


Figure 10-2: Benchmarking of Habanero Base Project (Sources: [1] European Geothermal Energy Council (EGEC), July 2013; [2] World Bank (ESMAP), June 2012; [3] US-EIA, April 2013; [4] GDY)

11. SCHEDULE


GEODYNAMICS
13 Dec 13 Version 2.0
Oct 2013
Dec 2013
Dec 2014
Dec 2016
Start 2017
Assess
Select
Develop
Execute
Operate
Complete Hab 1 / 4 Doublet
Commission 1 MW
Complete Closed Loop Testing
Reservoir model
Concept Scoping Study
Drilling Options
Field development Plan
Definitive Feasibility Study
FEED
Production Drilling & Plant Construction
Production
Project Initiation Decision
Concept Selection
Financial Investment Decision
Practical Completion
Reservoir
- Develop Habanero reservoir model
-Determine Habanero reservoir capacity and life term
- Reservoir Simulation model
- Scenario tree
- Recovery Mechanism
- Well Flow performance
- Completion Strategy
- Field Development Plan
- Production profile
Engineering & Project Management
- Plant Scoping Study
- Power generation optimisation
- Distribution option analysis
- Level 1 Project Cost Estimate
- Preliminary Feasibility Study
- Distribution Option Selection
- Delivery Concept
- Project Execution Plan
Cost estimate
- Capex / Opex
- Schedules
JV Management
Seek new JV Partner
Sales
Initial discussions with SANTOS / Beach Energy
Letter of Intent - LOI SANTOS / Beach
PPA Signed
Financing
Discussions ARENA to include 5 MW in REDP funding program
-Initial application
- Amounts to be staged

12. CONCLUSIONS

This document has outlined a Field Development Plan (FDP) for the Habanero EGS resource located near Innamincka in the Cooper Basin, South Australia. It presents the results of a study into the feasibility of an EGS project, nominally in the order of 7.5 MW_e, supplying power/heat to a local consumer in the Cooper Basin. It also discusses at length key learnings acquired by GDY during the exploration of three EGS resources in the Innamincka granites: Habanero, Jolokia, and Savina. This section presents the key conclusions of the study.

12.1 The Market

An investigation into potential customers revealed several existing loads and some future potential loads that could be suitable loads for a commercial scale EGS development. Santos has an existing ~8 MW_e electrical and a ~100MW_{th} heat load at their Moomba gas facility located ~70 km from Habanero. In addition, Santos has several satellite stations that have an electrical load of ~1 MW_e, of which Della and Dullingari are the closest, located ~30 km from Habanero. In addition, Chevron and Beach have plans to develop new gas production facilities in the future, which are expected to have similar loads.

Other smaller loads have been indentified, but their size alone is insufficient to justify an EGS development. Smaller consumers in the region typically use diesel generation and have a much higher cost of generation. However, due to their small size and potentially short operating life such consumers are only advantageous to a larger project underpinned by a Power Purchase Agreement (PPA) with a gas producer.

Gas producers would otherwise consume gas for their energy needs, and for FDP purposes, EGS has assumed to be competing with the opportunity cost of gas. This has been estimated at $7-9 /GJ, which equates to ~$70-$90 /MWh_e for electricity generation, and $30-$40 /MWh_{th} for heat generation. Direct heat is a better application of geothermal energy mainly due to the elimination of the large conversion efficiency losses associated with converting low grade heat into electricity.

12.2 The Habanero Reservoir

Key conclusions with regard to the Habanero EGS reservoir are:

- Significant knowledge has been gained in exploring and exploiting EGS resources.
- The Habanero reservoir is one single pre-existing fault, and essentially all fluid flow is via this fault with the majority of the granite rock having no permeability. This finding has significantly reduced the estimated amount of total recoverable energy, and the amount of energy that can be produced from one well, both of which undermine the commercial viability of EGS in the Cooper Basin.
- There is currently no technology available that can remotely identify and locate existing faults in granite rocks. Drilling is the only option, which leads to higher exploration risks for future EGS greenfield projects.

12.2.1 Wells and geophysics

The extent of the Innamincka Granite is interpreted from regional gravity data acquired over several gravity surveys. The granite shows up as a distinct gravity low which extends beyond the outline of the original GELs 97 and 98. Geoscience Australia has assisted delineating the 3D geometries of the known high-heat producing granites through the inversion of gravity data, which estimates the Habanero granite to have a thickness of over 10 km.

Conventional methods employed to understand and map the Habanero resource have proven to be generally unsuccessful, such as:

- Magnetic data for the region is not relevant because the granite does not have suitable magnetic properties.
- Analysis of existing 2D seismic data is not accurate for in-depth analysis of the Habanero granite body. Detailed analysis of the granite properties would require new, dedicated acquisition; however, the value of new data may be minimal due to current technical and science limitations.
- In 2003, Brent Geophysical Consulting concluded that it was effectively impossible to image faulting below the top of basement using seismic interpretation on the current data. However, they, and MBA Petroleum in 2010, were able to map the top of the granite structure.
- Two electromagnetic surveys have been undertaken by researchers from Japan but neither survey was able to provide additional information about the Habanero reservoir. An additional research project by the University of Adelaide is attempting to image the Habanero fracture within the granite by comparing MT data pre- and post- stimulation. This method has had positive results in other EGS projects, including Paralana, South Australia, and may provide additional understanding of the Habanero reservoir.

12.2.2 Geology

Stress magnitude analysis of Habanero clearly indicates a reverse faulting or over-thrust regime at reservoir depth. The ratio of horizontal stresses to vertical stress ($SH_{max}/Sh_{min}/S_v$) is estimated to be approximately 1.35-1.45/1.10-1.25/1.0. In this over-thrust stress regime, pre-existing, N-S striking, shallow dipping structures will stimulate first. Importantly, because these shallow dipping structures are critically stressed, stimulation will occur at pressures significantly less than the overburden stress (minimum principal stress, S_v). Hydraulic stimulation causes shear failure along pre-existing weaknesses (stress sensitive fault zones) which are optimally oriented to the recent stress field rather than creating new hydraulic tensile fractures.

Mapping of the stimulation induced seismicity was used to determine the extent of the Habanero reservoir. The cloud of seismic events now covers over 4 km^2. The seismicity from the Habanero 4 stimulation exhibits an area of reduced activity around and to the north of Habanero 1. This supports the theory of the "mud ring", which is thought to be the result of substantial drilling fluid losses during the drilling of Habanero 1 and significantly reduces injectivity around Habanero 1. Interpretation of the seismic data strongly suggests that the reservoir at Habanero is a fault that is dipping at 10° to the west south west. The Habanero Fault is interpreted to truncate against a vertical fault along the eastern boundary.

12.2.3 Heat in Place estimate

Using this simulation-derived temperature forecast, an assessment of the geothermal resources for three HGP development options has been prepared as detailed in the following table:

Parameter	Units	Value
Area of seismic cloud	km^2	4
Depth range	m	4,000 – 4,500
Thickness	m	500
Volume of granite	km^3	2
Average temperature	°C	243
Cut-off temperature	°C	180
Heat Capacity	$MJ/(m^3.K)$	2.6

Parameter	Units	Value
Heat in Place	PJ_{th}	330
Recoverable Thermal Energy (2 wells)	PJ_{th}	10
Recoverable Thermal Energy (4 wells)	PJ_{th}	20
Recoverable Thermal Energy (6 wells)	PJ_{th}	30

12.2.4 Productivity forecasts

Various models were created and calibrated against HPP data to determine production profiles for a large EGS development at the Habanero resource. HPP data and a Monte Carlo analysis was used to estimate production and injection flow rates of 25 – 45 kg/s per well, giving most likely estimates of 90 – 120 kg/s for a six well project, and 60 – 80 kg/s for a four well project. In addition, GDY carried out thermodynamic reservoir simulation of the Habanero field with AUTOUGH2. The model was used to select the optimum well layout, which was an inverted 4-spot or triangular layout; and to determine reservoir temperature drawdown over the 15 year project life, estimated to be ~30°C decline in average bottom hole flowing temperature. In addition, WellCAT was used to correct the simulated flowing bottom hole temperatures to their equivalent surface production temperatures.

12.3 Drilling

Drilling EGS wells in the overpressured Habanero reservoir is technically very challenging. GDY has accumulated a large body of knowledge and significant expertise in the drilling of HPHT wells. This is demonstrated through the drilling of Habanero 4 which was an outstanding technical success maintaining high well integrity and protecting the reservoir from damage. Key conclusions with regard to drilling FDP wells in the Habanero EGS reservoir are:

- Simpler well designs and CT drilling have the potential to significantly reduce well costs and provide less risk of reservoir damage than conventional mud drilling by utilising managed pressure drilling with a weighted brine.
- Despite significant potential cost improvements identified in FDP that reduce per well costs by ~70% compared to Habanero 4, EGS wells at Habanero remain expensive relative to the amount of energy produced.

12.3.1 EGS Drilling Challenges

The following issues contribute to the complexity and difficulties of drilling EGS wells in the Cooper Basin:

- The combination of high temperatures AND high overpressures.
- An over pressured zone is created by the Roseneath Shale (regional seal) that results in pressures of 5,000 psi above hydrostatic pressures.
- The reservoir is one regional, sub horizontal fault through a granite with varying strength at each intersection meaning that the range of pressures that can be applied to the fault without losses is narrow and varies.
- Other existing fractures in the granite have sufficient permeability to create losses/kicks and may contain high levels of CO_2 or H_2S which compromises drill fluid.
- Tectonically, the area is in compression, which requires careful management of minimum pressures to maintain wellbore stability issues and prevent borehole breakout.
- Low concentrations of Chlorine and H_2S, and high concentrations of CO_2 in the reservoir fluid cause issues with casing design and selection, and can affect drilling mud performance.

- Drilling fluid density is not constant with depth due to expansion of the fluid with temperature.
- Wells are subject to extreme pressure and temperature cycles:
  - Stimulation creates pressures of 7,000 psi at surface and reduces down-hole temperatures to 50°C.
  - Production increases surface temperatures to 230°C.
  - Load cycle requirements are not clearly defined.
  - Trapped fluid increases in pressure as the fluid is heated during production- this is particularly a concern in a completion annulus or free fluid in the cement (cement holiday).
- Although geothermal wells target hot water and steam, which is inherently less of a hazard than petroleum wells, the South Australian wells require that the HGP wells are drilled under the Petroleum Regulations rather than a geothermal specific code.

In order to manage these issues, GDY has instituted practices from the HPHT industry such as downhole modelling and fingerprinting, and from the geothermal industry such as cementing practices, management of thermal cycles and geothermal tools. GDY has also formed strategic partnerships to address the major challenges - key partners have included Blade Energy for engineering support, Packer's Plus and Welltec for completions, and Halliburton for Reverse Cementing.

12.3.2 Key drilling lessons learnt

The key drilling lessons learnt during exploration of the Habanero reservoir are:

- The rheological properties of the drilling fluid can change significantly as a function of temperature and pressure. Conventional drilling fluid measurement and control techniques are not adequate in the Habanero wells. Extensive fluid modelling and calibration is required to accurately determine downhole pressure under various drilling operations, most importantly when drilling through the fracture. Accurate downhole drilling fluid rheology is also required or the placement of cement and displacement of the drilling fluid.
- Habanero 3 had a casing failure in April 2009 caused by caustic stress corrosion cracking due to the presence of a high pH environment created by unset cement. Contributing factors were the use of high tensile strength material (150 ksi) which is susceptible to cracking type failures, thermal cyclic loading which concentrated the annular fluid through boiling off and broke the passivating corrosion layer and the presence of tong marks which became the initiation point.

Key recommendations to prevent reoccurrence, all of which were successfully incorporated into the drilling of Habanero 4 are:

  - Use lower strength casing that is less susceptible to cracking type failures.
  - Eliminate fracture initiation points through the use of non-marking dies and tight casing specifications.
  - Ensure cement is set at surface with no pockets of free water or un-displaced mud to eliminate the potential for caustic environments and localised high pressure events that can collapse casing.
- Installing completions in the Habanero wells is particularly difficult and complications have occurred in the installation of all completions attempted. Completions are not recommended and have been eliminated from the conceptual FDP well designs.
- Corrosion in the wells has been modelled and calibrated against a calliper log obtained in Habanero 1. Corrosion levels are relatively low as the initial high temperature flows create a passivating layer that protects the wells from future corrosion.

- Drilling fluid systems require a high level of reliability as consistent pump performance is required to maintain the finger-printing repeatability required to detect kicks and for primary well control.
- Larger drill pipe is recommended, such as 5-1/2 inch as opposed to a more standard size of 4-1/2 inch, as this minimises vibration issues and improves annular velocity and hole cleaning.
- Contingency planning and crew training is critical as reactions that are normally trained into rig crews, particularly surrounding well control, are not appropriate for HPHT wells. It is recommended that in addition to the standard Risk Assessment and Drill Well On Paper (DWOP) review sessions, training is provided in HPHT practices; including finger printing; and that contingency plans for envisaged problems are prepared and communicated in advance.

12.3.3 Recommended well design for a future EGS development

The FDP identifies and discusses drilling methods and well designs that have the potential to maintain high well integrity and protect productivity of the reservoir, while achieving major cost reductions. Key innovations in the well design included reducing the number of casing strings from three to two and reducing hole size from 8.5 inch to 6 inch, both contribute to reducing rig size and material and time related costs. The completion was replaced with two cemented casing strings that are designed to withstand all foreseeable loads, which reduces complexity, risk and cost. Furthermore, the main fracture is to be drilled with a CTU and weighted brine rather than conventional drilling rig and drilling fluid; this minimises the risk of damage to the main fracture and simplifies operations. These innovations result in a cost reduction from ~$50 million for Habanero 4 to an average per well cost of ~$16.5 million for a five well campaign.

The recommended well design uses a CTU to drill the reservoir section. A trial of a high temperate turbine and diamond impregnated bit on coil is recommended, prior to finalising the drilling program, to establish if the ROP is adequate. If ROP is not adequate, the back up well design presented (the 2-String option) results in an average cost estimate of $19.4 million/well in a 5 well campaign.

Detailed Well design and construction should be done according to the GDY's "Well Engineering Management System Description and Processes" (WEMS) and Geodynamics "Drilling and Completions Technical Standards Manual". This work will need to include confirmation of acceptability of well design with all stakeholders.

Aspects of the well design that need to be addressed in detailed design include:

- A regional formation strength study to increase confidence that acceptable casing shoe tests can be achieved at the nominated casing setting depths.
- Confirming that the Double barrier policy can be satisfied through fixed (cemented) barriers only- no removable barrier.
- Modelling of the reverse cementing jobs to confirm displacement issues from the past well are addressable by reducing the well size (increasing annular velocity) and increasing fluid viscosities.
- Demonstrating the ability to penetrate granite on coil tubing by a trial of the impreg and turbine in granite. ROP impreg optimisation is a major technology challenge that can provide significant value with both of the discussed well designs.
- Selecting of casing point for 7 inch casing before drilling open hole with CT.
- Confirming that the corrosion allowance is satisfactory.
- NACE Fit-for-Purpose testing of the 125 ksi casing material.

12.4 Power generation facilities

Key conclusions with regard to production facilities of HPHT EGS developments are:

- Design, construction and operation of production facilities at Habanero is challenging and costly due to the extreme process conditions, remote location, and small scale. In addition, the large distance to potential customers can add significant transmission costs to a project.
- The high pressure brine system, in particular the brine piping, contributes significantly to increasing overall project costs, ~25% of total project CAPEX.
- The cost of EGS wells justifies investment in higher cost plant with higher thermal and utilisation efficiency because this results in a lower specific CAPEX for the overall project.
- Process heat to Moomba is cost-prohibitive, but potentially attractive for a co-located consumer at Habanero.
- Transmission costs are relatively high for small EGS developments in the Cooper Basin.

12.4.1 Power generation plant selection

The geothermal power generation facilities consist of two key components, the plant, and the brine system. Some of the related important conclusions and findings in the FDP were:

- Power Plant
  - A wide range of different power plant technologies exist with mostly similar costs and performance. The FDP revealed that binary type power plants with supercritical refrigerants are likely to be optimum for an EGS development at Habanero.
  - Reuse of existing plant in a larger development is likely to provide a sub optimal outcome given the inherent inefficiencies.
  - Availability expectations for supplying a remote gas producer are likely to be challenging for an EGS project especially with a single transmission line.
  - Operating costs incurred are significant in the Cooper Basin, especially for small developments and are dominated by staff costs, either by direct wages or through accommodation, travel and incidentals.
- Brine System
  - Brine heat exchanger costs can be reduced significantly through offshore manufacture and incorporating into packaged power plant providers scope.
  - CBH carried out a holistic cost optimisation study encompassing materials, fabrication and construction costs to identify the optimum high pressure brine material. CBH identified DN17175 X20CrMoV12-1, equivalent to EN10216-2 X20CrMoV11-1 material, to be a potentially cost saving material. Further work is required to qualify the material for the service and confirm accurate supply costs.

12.5 Commercial viability

The key conclusions with regard to the commercial viability of small scale EGS development at Habanero supplying power/heat to a local consumer in the Cooper Basin are:

- Capital cost estimates for a future Habanero EGS power development are expensive relative to published estimates for other geothermal projects around the world.The high pressure high temperature process conditions have a significant effect on the capital costs indicated by the wells being the dominant contributor to total project capital costs, ~50%, and the significant CAPEX associated with high pressure brine system.

- Provision of EGS electricity is not assessed to be competitive with gas fired generation, but provision of EGS process heat is competitive.
- The direct heat project shows significant potential to be competitive on an unsubsidised basis with gas. The best chance for commercial success of an EGS direct heat project is a future gas production facility co-located at the Habanero resource. The project is not likely to be viable for a customer located any great distance from Habanero due to the costs of the pipeline.

12.6 Key recommendations

The key conclusions and recommendations the FDP are:

- The economic viability of further development of power generation at Habanero remains challenging due to high capital costs; however, supply of direct process heat to a closely located gas plant is assessed to be viable without subsidy or assistance.
- Close engagement with gas producers considering future developments in the region should be pursued to fully assess the potential of EGS as a viable energy source for direct heat.

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Appendix A Formation Brine Chemistry

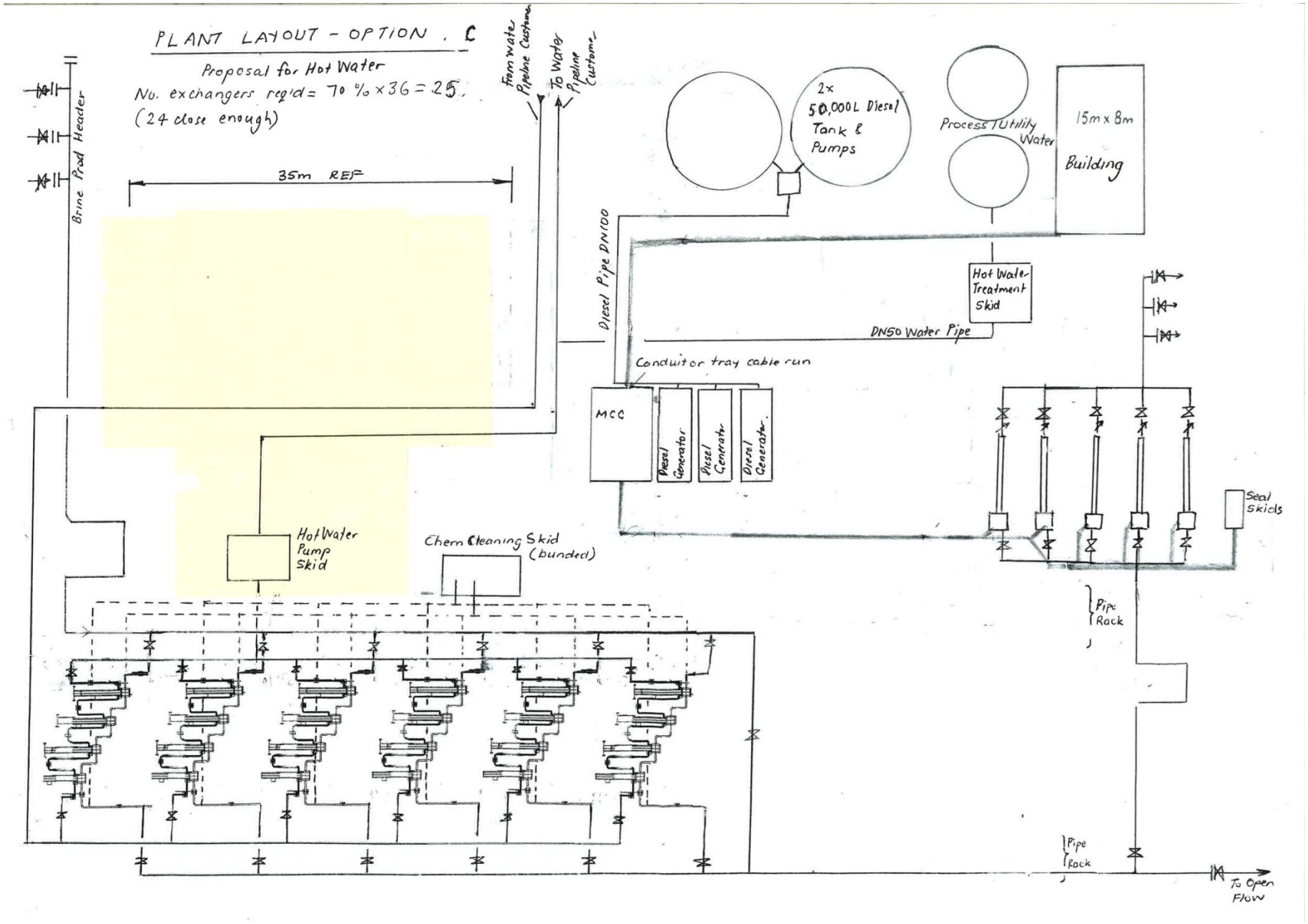
Extract from Brown, 2013. Habanero 4 Chemical Sampling July 2013.

		SAMPLE 1	SAMPLE 2	SAMPLE 3	SAMPLE 4	HAB4 Nov '12	HAB3
pH at 250°C			6.06	6.18		6.03	5.94
Boron	mg/L	223	229	229.0	227	253	196
Caesium	mg/L	40	39.1	42.3	39	39.5	42
Calcium	mg/L	41	39.1	39.4	41	45.1	24?
Chloride	mg/L	7550	7567	7557	7548	8526	7346
Fluoride	mg/L	15.6	15.9	16.2	16	16.7	16
Iron	mg/L	1.9	0.55	0.50	1.4	1.3	
Lithium	mg/L	216	215	215	216	243	188
Magnesium	mg/L	2.2	2.0	2.02	2.1	0.39	0.23
Potassium	mg/L	670	682	672	683	719	570
Rubidium	mg/L	12.5	14.7	14.6	14.1	17.2	15
Silica (as SiO2)	mg/L	475	483	474	474	497	450
Sodium	mg/L	4378	4346	4368	4383	5140	3830
Sulphate	mg/L	28	27.7	27.9	28	63.0	37
Antimony	mg/L	1.6	1.34	1.35	1.8	2.44	3.1
Arsenic	mg/L	1.8	1.9	1.7	1.8	1.88	2.6
Argon	mg/L		5.12	4.16		7.69	8.5
Carbon Dioxide (total)	mg/L		14127	10902		18660	18280
Helium	mg/L		20.3	14.4		22.2	19
Hydrogen	mg/L		0.269	0.216		.0048	.41
Hydrogen Sulphide (total)	mg/L		15.3	13.6		1.007	80
Methane	mg/L		868	715		1320	980
Nitrogen	mg/L		487	388		701	560
Ammonia (total)	mg/L		2.54	2.33		9.6	2.0

Notes:

- Sample 1 and sample 4 are from the wellhead, with no gas collection
- Sample 2 and sample 3 are combined steam and brine samples collected with the miniseparator at the low pressure sampling point on the side stream and corrected by calculation to the total flow.
- HAB4 Nov '12 was one of the typical analyses from the sampling on November 12, 2012
- HAB3 samples were collected in March 2008
- Reservoir carbon dioxide and ammonia concentrations are calculated as the sum of the measured water concentration plus the calculated steam concentration.

Appendix B
Plant Layout


PLANT LAYOUT - OPTION . C
Proposal for Hot Water
No. exchangers req'd = 70 % x 36 = 25.
(24 close enough)
Brine Prod Header
35m REF
Farm water Pipeline Customer
To Water Pipeline Customer
2x 50,000L Diesel Tank & Pumps
Process / Utility Water
15m x 8m Building
Diesel Pipe DN100
Hot Water Treatment Skid
DN50 Water Pipe
Conduit or tray cable run
MCC
Diesel Generator
Diesel Generator
Diesel Generator
Seal Skids
Hot Water Pump Skid
Chem Cleaning Skid (bunded)
Pipe Rack
Pipe Rack
To Open Flow

Appendix C Detailed Capital Cost Estimates

Compilation of Costs for Different Projects

		Project 1	Accuracy	Contingency	Project 2	Accuracy	Contingency	Project 3	Accuracy	Contingency	Project 4	Accuracy	Contingency	Project 5	Accuracy	Contingency	Project 6	Accuracy	Contingency
		5-5.5MWe to Moomba (formerly "Base Project") and other Commercial Loads			5-5.5Mwe to New Gas Plant (close-by) and other Commercial Loads			2.5MWe to Moomba and other Commercial Loads			2.5MWe to New Gas Plant (close-by) and other Commercial Loads			6MWth (170 deg C) Process Heat to Moomba			6MWth (170 deg C) Process Heat to New Gas Plant (close-by)		
		5 new wells			5 new wells			3 new wells			3 new wells			5 new wells			5 new wells		
DRILLING																			
Average Well Cost		$ 16,449,918	25%		$ 16,449,918	25%		$ 17,275,646	25%		$ 17,275,646	25%		$ 16,449,918	25%		$ 16,449,918	25%	
Campaign Cost		$ 82,249,592	25%		$ 82,249,592	25%		$ 51,826,938	25%		$ 51,826,938	25%		$ 82,249,592	25%		$ 82,249,592	25%	
SURFACE INFRASTRUCTURE																			
Packaged power plant																			
Plant	Selected costs as explained in body of report. Convert quoted USD to AUD at $0.92. US$23M=A$25M	$ 25,000,000	30%	15%	$ 25,000,000	30%	15%	$ 13,000,000	40%	20%	$ 10,700,000	40%	20%	$ -			$ -		
Delivery FOB International-> Aust Port (note transport within Aust covered	TAS advised delivery cost of $990K. Allow 40% reduction for smaller plant option.	$ 1,076,000	20%	10%	$ 1,076,000	20%	10%	$ 594,000	20%	10%	$ 594,000	20%	10%	$ -			$ -		
Allowance for inter-module pipe and cable	Estimate	$ 500,000	30%	15%	$ 500,000	30%	15%	$ 500,000	30%	15%	$ 500,000	30%	15%	$ -			$ -		
Brine heat exchangers	Included in power plant costs where possible. For process heat, need 85MWth, ie x 36 shells. Re-use 4 HPP shells. Thus prchase 32 shells. Cost = 32/36 x $8.4M heat exchanger reference price = $7.5M. Note high accuracy due to pricing from detailed design drawings.	$ -			$ -			$ -			$ -			$ 7,500,000	15%	15%	$ 7,500,000	15%	15%
Hot water pumping skid	Extrapolated from MCP pumps on HPP project													$ 200,000	30%	10%	$ 200,000	30%	10%
Water pipeline, RO & chemical dosing and fill system.	Estimate													$ 125,000	30%	10%	$ 125,000	30%	10%
Extra diesel tankage	Estimate													$ 150,000	30%	10%	$ 150,000	30%	10%
Balance of Plant	Use CBH submission for Option B layout and X20 piping material.	$ 20,271,044	30%	0%	$ 20,271,044	30%	0%	$ 12,500,000	40%	0%	$ 10,300,000	40%	0%	$ 17,000,000	40%	0%	$ 17,000,000	40%	0%
Construction (CBH)																			
	For smaller plant, slight reduction only in BOP costs (50% of Option B from CBH)																		
	For hot water project, assume costs are 90% of the Option A estimate for multiple heat exchangers, ie $17M																		
	Assume that Producer well P1 (740m long) is piped using re-used HPP DN150 piping																		
	Contingency already allowed by CBH																		
Procurement (GDY estimate)																			
Refurbish 2 x existing HPS pumps	2 x $80,000	$ 160,000	5%	5%	$ 160,000	5%	5%	$ -	5%	5%	$ 160,000	5%	5%	$ 160,000	5%	5%	$ 160,000	5%	5%
3 x new HPS pump assemblies (complete w/ base)	Based on 2009 quote for additional BRP for HPP. $560K-$88K (Flowserve seal)=$472K. Includes motor & thrust chamber etc. Apply escalation from 2009 to 2013 @ 3% pa. Cost = $531K (each)	$ 1,593,000	5%	5%	$ 1,593,000	5%	5%	$ 1,700,000	5%	5%	$ 531,000	5%	5%	$ 1,593,000	5%	5%	$ 1,593,000	5%	5%
1 x additional /redundant seal skid	HPP cost was $290K, less $140K for two seals	$ 150,000	5%	5%	$ 150,000	5%	5%	$ 150,000	5%	5%	$ 150,000	5%	5%	$ 150,000	5%	5%	$ 150,000	5%	5%
initial complement of pump seals (x5)	5 x $70K	$ 350,000	5%	5%	$ 350,000	5%	5%	$ 350,000	5%	5%	$ 350,000	5%	5%	$ 350,000	5%	5%	$ 350,000	5%	5%
Fire suppression system for transformers and MCC	Estimate	$ 200,000	30%	10%	$ 200,000	30%	10%	$ 200,000	30%	10%	$ 200,000	30%	10%	$ -			$ -		
1 x 500-1000kVA diesel generator	Allowance based on HPP unit ($160K). Note however that extra cost must be allowed for the hot water projects, where up to 1600KW of diesel driven brine pumping is required.	$ 200,000	10%	10%	$ 200,000	10%	10%	$ 200,000	10%	10%	$ 200,000	10%	10%	$ 500,000	30%	10%	$ 500,000	30%	10%
1 x 11-66kV 10MW transformer	Included in Cowell's transmission estimate below.																		
Allowance for electrical cabling and tray	Note no engineering available to support estimate.	$ 750,000	30%	10%	$ 750,000	30%	10%	$ 400,000	30%	10%	$ 400,000	10%	5%	$ 400,000	10%	5%	$ 400,000	10%	5%
Allowance for instrumentation	Note no engineering available to support estimate.	$ 750,000	30%	10%	$ 750,000	30%	10%	$ 400,000	30%	10%	$ 400,000	10%	5%	$ 400,000	10%	5%	$ 400,000	10%	5%
Wellhead ESD valves.	HPP cost was $55K. Escalate 2011-2013 @ 3%pa. Cost= $58.5K each. Assume 5 new for base project and 2 new for smaller project	$ 293,000	5%	5%	$ 293,000	5%	5%	$ 117,000	5%	5%	$ 117,000	5%	5%	$ 293,000	5%	5%	$ 293,000	5%	5%
Production well control valves	HPP cost was $55K. Escalate 2011-2013 @ 3%pa. Cost= $58.5K each. Assume 5 new for base project and 2 new for smaller project	$ 293,000	5%	5%	$ 293,000	5%	5%	$ 117,000	5%	5%	$ 117,000	5%	5%	$ 293,000	5%	5%	$ 293,000	5%	5%
Injection check valves	HPP cost was $16K. Escalate 2011-2013 @ 3%pa. Cost= $17K each. Assume 2 new	$ 34,000	5%	5%	$ 34,000	5%	5%	$ 34,000	5%	5%	$ 34,000	5%	5%	$ 34,000	5%	5%	$ 34,000	5%	5%
Manual (gate) valves.	Assume 60 valves if separate BHX and 30 valves if integrated exchangers. Work off 30 valves. Brine service, 360 barg and 260 deg C, DN200. Unit price for HPP at DN150 was $30K each. Index by 3%pa and index for size at (200/150)^1.2. Unit cost=$45K. **Cost = 30 x $45K=$1,350K, or less for smaller project.**	$ 1,350,000	20%	10%	$ 1,350,000	20%	10%	$ 1,000,000	20%	10%	$ 1,000,000	20%	10%	$ 1,350,000	20%	10%	$ 1,350,000	20%	10%
Other piping items	PSVs, spring hangers, SP items, etc	$ 250,000	25%	25%	$ 250,000	25%	25%	$ 250,000	25%	25%	$ 250,000	25%	25%	$ 250,000	25%	25%	$ 250,000	25%	25%
Hot Water Tranmission Pipelines	For local plant option, remove pipeline costs	$ -			$ -			$ -			$ -			$ 800,000,000	50%	25%	$ -	50%	25%
Other Costs																			
Spare Parts		$ 1,000,000	20%	10%	$ 1,000,000	20%	10%	$ 500,000	20%	10%	$ 500,000	20%	10%	$ 500,000	20%	10%	$ 500,000	20%	10%
Commissioning	$1800/d for contractors x 4 persons x 13 wks= $163K + $90K travel= $200K	$ 200,000	20%	10%	$ 200,000	20%	10%	$ 200,000	20%	10%	$ 200,000	20%	10%	$ 200,000	20%	10%	$ 200,000	20%	10%
Permits	Not accounted for yet																		
Insurances	Not accounted for yet																		
Surveys	Not accounted for yet																		
Accommodation, travel, logistics								$ 3,000,000	20%	20%									
Owners Costs Billed to Project	Assume 8 staff x $220K avg salary x 3 year project development = $5.2M	$ 5,200,000	20%	10%	$ 5,200,000	20%	10%	$ 5,200,000	20%	10%	$ 5,200,000	20%	10%	$ 5,200,000	20%	10%	$ 5,200,000	20%	10%
Design Costs	5% x $70m subtotal excl transmission and wells	$ 3,500,000	20%	10%	$ 3,500,000	20%	10%	$ 3,500,000	20%	10%	$ 3,500,000	20%	10%	$ 3,500,000	20%	10%	$ 3,500,000	20%	10%
	Total for Surface Only (50th percentile excl cty)	**$ 63,120,044**			**$ 63,120,044**			**$ 43,912,000**			**$ 35,403,000**			**$ 840,148,000**			**$ 40,148,000**		
	SURFACE 99th percentile cost + cty	**$ 85,506,457**																	
	SURFACE 1st percentile cost + cty	**$ 51,641,131**																	
	Total for Surface and Drilling (excl transmission)	**$ 145,369,636**			**$ 145,369,636**			**$ 95,738,938**			**$ 87,229,938**			**$ 922,397,592**			**$ 122,397,592**		
	For gas plant only 5km away, powerline construction would be completely different (assume all 11kV). Using Cowell cost elements as a guide, assume $524K design + $241K (LV distbn) + + $722 K for lateral + $176K (mob/demob) + one 11kV substation at Habanero $2,579K. Total = $4,242K. Cowell provided a separate email of costs for a 5MW line to convey 2.5MWe ($14.2M).																		
Electrical Transmission	For Project 4, assume a 10% saving from Project 2.	$ 19,800,000	10%	10%	$ 4,242,000	10%	10%	$ 14,200,000	10%	10%	$ 3,800,000	10%	10%	$ -			$ -		
	Total Incl Drilling and Transmission	**$ 165,169,636**			**$ 149,611,636**			**$ 109,938,938**			**$ 91,029,938**			**$ 922,397,592**			**$ 122,397,592**		
	TOTAL PROJECT 99th percentile cost + cty	**$ 212,078,448**																	
	TOTAL PROJECT 1st percentile cost + cty	**$ 133,128,325**																	