AUSTRALIAN GEOTHERMAL ENERGY GROUP

Geothermal Code Committee

Geothermal Lexicon For Resources and Reserves Definition and Reporting

Edition 2

Compiled by Lawless, J. for The Geothermal Code Committee

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Effective November 2010

Prepared by:

The Australian Geothermal
Reporting Code Committee (AGRCC)

A Joint Committee of the Australian Geothermal Energy Group (AGEG)
and the Australian Geothermal Energy Association (AGEA)

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Introduction

Background

The Australian Geothermal Energy Group and the Australian Geothermal Energy Association have formed a Geothermal Code Committee, to produce and maintain a methodology for estimating, assessing, quantifying and reporting Geothermal Resources and Reserves that will promote transparency, materiality and competence. The methodology will:

1. Provide a basis that is satisfactory to investors, shareholders and capital markets such as the Australian Securities Exchange, in the same way that there are recognised Codes for mineral and petroleum deposits.
2. Be applicable to the type of geothermal projects that are likely to be undertaken in Australia, given that many of the Australian Geothermal Plays currently under investigation are different from most of those which have so far been developed commercially in other countries.
3. At the same time, be applicable to Geothermal Plays in other countries, since the geothermal energy industry is expanding globally. This includes established projects with a production history as well as greenfield sites.
4. The Code Committee has developed two documents, which have been based on extensive discussions, public presentation and review of earlier drafts.

The first is the Australian Code for Reporting of Exploration Results, Geothermal Resources and Geothermal Reserves (the 'Geothermal Code' or 'Code'). It covers a minimum, mandatory set of requirements for the public reporting of geothermal resource and reserve estimates.

The second is this document, the Lexicon. This document provides guidance on how Geothermal Resources and Reserves can be estimated for reporting purposes. The techniques described in the Lexicon are generally not a mandatory part of the Geothermal Code. **The one exception to this in the Second Edition of the Code is the default mandatory use of the Lexicon as the source of values for Recovery Factors to convert stored heat to recoverable energy which in the Second Edition of the Code, is by definition the Resource** (which is a major change from the first edition of the Code). However, *any* significant deviations from the Lexicon should be disclosed and explained when reporting under the Geothermal Code.

The Geothermal Code is intended to be a living document. Once established, however, it will require a formal process to change. This process will be managed by the joint AGEG/AGEA Reporting Code Committee, in consultation with key stakeholders. The Second Edition of the Code was agreed in late 2009. Since the Code refers to the Lexicon, there are consequent changes required in the Lexicon.

The Geothermal Lexicon is more discursive than the Code, less formal and will be subject to more frequent revisions. This is the first such revision.

Contacts

Questions or comments regarding this Lexicon or the Code should be directed to Peter Reid, Committee Chair: preid@petratherm.com.au.

Scope

This document focuses on geothermal energy for electricity generation only and does not explicitly consider direct heat uses. However the principles used here could be applied equally well to direct use projects and they are not excluded from the Geothermal Lexicon. The methodology addresses both naturally permeable aquifers and engineered geothermal systems (EGS)[1].

The Code and Geothermal Lexicon are not designed to include the use of geological masses to store and recover thermal energy but may be relevant in that domain. The methodology has to address both naturally permeable aquifers and those where permeability is artificially enhanced ('engineered'). Environmental, policy and regulatory constraints on projects are not considered in any detail except to note that they should be reported on if they will impact on the power price assumed, or more broadly on the project economics.

Types of Geothermal Resource

A simplistic division of geothermal resources is into those with a direct magmatic (i.e. usually volcanic) heat source, such as those occurring near tectonic plate boundaries (e.g. New Zealand, Philippines, Indonesia, Iceland, Japan) or mantle hot spots (e.g. Hawaii, Yellowstone), and those without (Australia, most of Europe except Italy and Greece).

Magmatic-related geothermal systems are much more restricted in their occurrence on a world scale, but generally much hotter at an accessible depth, of high natural permeability, and so easier to exploit for power generation. They may include natural two-phase zones. The majority of the ~12,000 MWe of currently installed geothermal electricity generation worldwide taps resources of this type, mostly without fluid production pumping.

Amagmatic systems are much more widespread but cooler at shallow depths, contain only single phase fluids, and are commonly used for direct heat applications, often with the use of downhole pumps.

Because of the diverse range of possible reservoir characteristics, the resource characteristics should be defined in any statement of resources or reserves, covering at least the following.

- Whether the project will rely on natural or enhanced permeability.
- Whether fluid in the reservoir is naturally convecting fast enough to establish a non-conductive temperature profile with depth, as is common in naturally highly permeable magmatically-heated reservoirs which within the upflow zone often approximate boiling point for depth from the water level; or whether temperature profiles are conductive as in many amagmatic situations. This is an important and fundamental factor since it is dependent on both the temperature and the permeability, and it defines whether or not:
    - Near surface heat flow can be reliably extrapolated to depth. If there is natural convection then especially in elevated terrain, near surface temperature gradients (which are often conductive) may give unrealistically high temperatures when extrapolated to depth.

1 See Glossary, Appendix C

    - There is likely to be natural hot fluid recharge over the lifetime of the geothermal project. Where permeability is low and temperature gradients are conductive, it is unlikely there will be any significant quantity of heat added to the system from outside the volume assessed as the resource over a project life of decades. In contrast in highly permeable natural reservoirs there might be significant natural heat flux through the system but pressure draw down due to exploitation can stimulate the vertical recharge to several times the pre-existing rate, thus adding significantly to the stored heat reserves.
    - There are likely to be upflows and downflows in response to production.
- If the project is based on an aquifer which can on geological grounds be anticipated to be laterally extensive (especially if it extends well outside the tenement boundary), some indication of that extent and quantification of its hydrology, since there could be significant natural recharge, albeit of fluid at similar temperature to that already in place in the exploited zone.
- Whether fluid in the reservoir is naturally single phase or two-phase, including fluids that are two-phase because of high non-condensable gas fractions rather than steam.
- An indication of fluid pressures, though this can simply be summarised for example as 'hydrostatic' or 'boiling point for depth hydrostatic'.
- Some indication of expected fluid chemistry within broad categories.
- Some indication of expected reservoir rock types.
- The nature of primary porosity and fracturing. For fracture porosity, the nature and disposition of fractures/joints/faults should be described, as it may impact significantly on heat recovery.
- Whether the project will rely on pumping or natural flow.
- If it is not a greenfield project, the details of the production history and reservoir response including any indication of reinjection returns.
- A tabulation of suggested parameters to report is given in Appendix D, which is Table 2 of the Code.

Similarities and Differences: Minerals and Petroleum Codes Vs. Geothermal

Derivation from the Minerals and Petroleum Codes

Methodologies for classifying reserves and resources are well established in the petroleum and mineral industries.

The Society of Petroleum Engineers (SPE) and the World Petroleum Congress (WPC) have jointly proposed definitions of standard terms for booking petroleum reserves. Their Guidelines for the Evaluation of Petroleum Reserves and Resources (SPEE/WPC, 2001) are drawn upon significantly here for methodology, as is the more recent Petroleum Resources Management System (SPE, WPC, AAPG, SPE 2007).

The minerals industry has converged on a methodology that is consistent across the main mining jurisdictions and is manifested in codes applied by the Canadian Institute of Mining, Metallurgy and Petroleum (CIM) and the Australasian Institute of Mining and Metallurgy/Australian Institute of Geoscientists Joint Ore Reserves Committee (JORC). These minerals industry codes conform to the international CRIRSCO standard[2]. The Australian Geothermal Code is aligned with the JORC Code.

The mineral and petroleum approaches both broadly include a two-dimensional classification based on:

1. Reliably of the information defining the physical resource, and
2. Commercial extractability of the resource.

Those distinctions are applied here to geothermal.

How Geothermal Energy Differs From Petroleum or Minerals

Extraction of geothermal resources has many similar characteristics to extraction of petroleum resources, but the ‘Geothermal Resource’ relates to the thermal energy content of the fluid and its host rock, rather than the fluid itself. Extraction of geothermal resources also involves a variety of thermodynamic processes not observed in petroleum extraction. Mineral resources generally have greater variability and less continuity and so require greater sampling density to assure the magnitude of contained resource.

Geothermal resources in convective hydrothermal systems further differ from both minerals and petroleum resources by being renewable through recharge, albeit usually at a slower rate than energy is extracted. The rate of this recharge can vary significantly from system to system, and can be stimulated to a varying degree by production.

Unlike most minerals and petroleum products which have an internationally defined dollar value, electrical energy prices can vary by an order of magnitude from place to place both because of physical alternative sources of supply and regulatory policies. Therefore the ‘cut-off grade’ for geothermal resources cannot be defined as a single internationally applicable number. It is highly country and region specific.

Furthermore, in the case of electricity generation, the ‘cut-off grade’ has to take into account the practical limitations and cost of the conversion process. For example, it is technically feasible to generate power from fluid at 100°C or less, but it is only economic to do so in a few locations. Some consideration also has to be given to the scale of the proposed development, as there are economics of scale in geothermal projects especially as they need to be based on a finite number of wells.

2 http://www.crirsco.com/welcome.asp

Geothermal projects where economics are the prime driver are typically sized to fully utilise a resource over a period of about 20 to 25 years that relates to the life of the wells and energy conversion plant, with a suitable margin for contingencies. It is therefore important to state the reserves in terms of the rate of extraction.

Preferred Approach

General Principles

A fundamental principle in the Code is that the essential feature of a Reserve as opposed to Resource is that it takes into account commercial viability. 'Reserves' are defined as the part of the resource that is commercially extractable and 'Resource' as the as yet sub-commercial component.

Commercial viability depends on a range of technical and economic factors. The SPE Guidelines recommend the term Reserve should not be used except with reference to a specific project, and preferably where development is planned within a set time frame of around five years. However, that time frame is considered too restrictive for current geothermal projects in Australia. In the Geothermal Code, and unlike some approaches in the mineral industry, it does not mean that a full, costed and financially modelled feasibility study for the specific project under consideration has to be completed before any reserves can be declared.

If a project involves an innovative application of technology, it may be necessary for certain steps to be taken to regard the concepts involved as sufficiently proven to be able to declare a Reserve. But the level of detail required for 'proof of concept' is substantially less than a full commercial feasibility study. Rather, definition of what constitutes Reserves can be done through some industry guidelines for what is commercial in the context of the conversion technology that is expected to be applied to the resource.

Geothermal Resource estimates are not precise calculations, being dependent on the interpretation of limited information on the location, depth and extent of the body of heat and on the available geoscientific results. Reporting of Thermal Energy in Place and Recoverable Thermal Energy figures should reflect the relative uncertainty of the estimate by rounding off to appropriate significant figures and, in the case of Inferred Geothermal Resources, by qualification with terms such as 'approximately'.

In most situations, rounding to the second significant figure should be sufficient. For example: 31 MW_{th} and 6.5 MW_e. There will be occasions, however, where rounding to the first significant figure may be necessary in order to convey properly the uncertainties in estimation.

To emphasise the imprecise nature of a Geothermal Resource estimate, the final result should always be referred to as an estimate not a calculation.

Categories of Resources and Reserves

Categories of Resources and Reserves are important to provide explicit understanding of the certainty (quality and reliability) of the information that is used to estimate their magnitude. Each category should provide a real sense of meaning to an investor with regard to how well the energy potential is defined and whether that energy can be realistically extracted under present conditions or requires improved technology or market conditions to be realised.

The classification regime for geothermal energy resources under the Geothermal Code is illustrated in Figure 1.

The term **Geothermal Play** is used as an informal qualitative descriptor for an accumulation of heat energy within the Earth's crust. It can apply to heat contained in rock and/or fluid. It has no connotations as to permeability or the recoverability of the energy, although it implies an intention to investigate those parameters. A Geothermal Play does not necessarily imply the existence of a Geothermal Resource or Reserve and quantitative amounts of energy must not be reported against it.

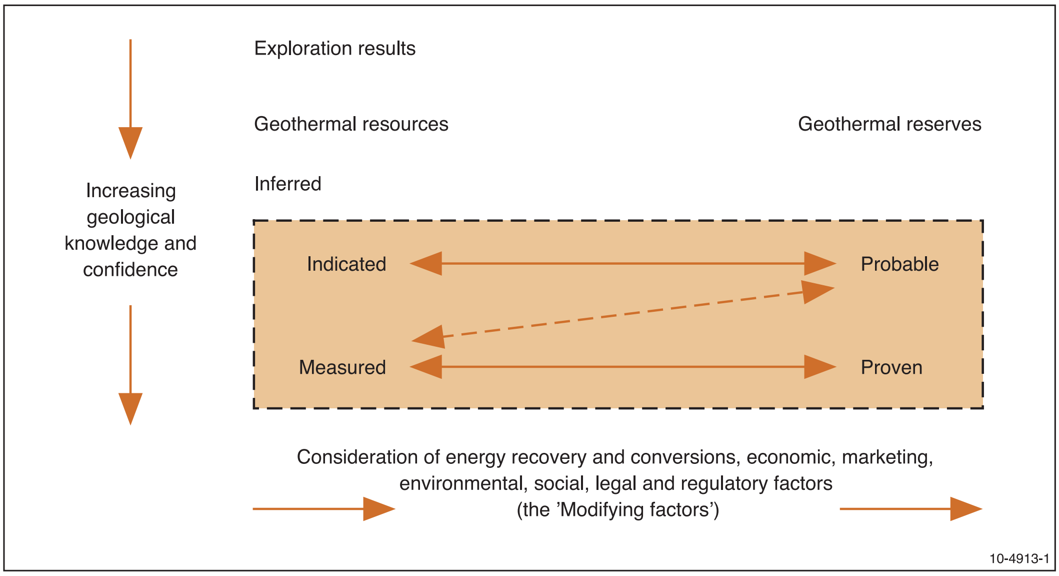

Figure 1: Relationship between Exploration Results, Geothermal Resources and Geothermal Reserves.

The Geothermal Code recognises three categories of Geothermal Resource (Inferred, Indicated and Measured) based upon increasing levels of geological knowledge and confidence, which directly affect the estimated probability of occurrence. Geothermal Reserves are further estimated from Geothermal Resources by consideration and application of 'Modifying Factors' which directly affect the likelihood of commercial delivery (e.g. production, economic, marketing, legal, environmental, land access, social and governmental factors). Two categories of Geothermal Reserve are recognised (Probable and Proven) based upon confidence in both the underlying Geothermal Resource estimate and the Modifying Factors. General relationships and pathways between the various Geothermal Resource and Reserves categories that are permitted under the Geothermal Code are as shown in Figure 1.

'Exploration Results' include data and information generated by exploration programmes that may be of use to investors. The reporting of such information is common in the early stages of exploration when the quantity of data available is generally not sufficient to allow any reasonable estimates of Geothermal Resources.

Examples of Exploration Results include results of hot springs/fumarole sampling, surface heat flow, geochemical results and geophysical survey results, conductivity measurements, temperature measurements and temperature extrapolations (to a reasonable degree and on a rational basis).

Reports must include relevant information such as exploration context, type and method of surface sampling, type and method of geochemical analysis, type and method of geophysical surveys, land tenure status plus information on any of the other criteria that are material to an assessment. Where analytical or measurement results are reported, the report must include all results, along with sample type, location, analytical methods, etc. Reporting of selected information such as measurements from isolated drill holes or surface samples without placing them in perspective is unacceptable.

A **'Geothermal Resource'** is a Geothermal Play which exists in such a form, quality and quantity that there are reasonable prospects for eventual economic extraction. If there is no reasonable prospect for eventual economic extraction then the energy in question should not be included in estimates of Geothermal Resources. The location, quantity, temperature, geological characteristics and extent of a Geothermal Resource are known, estimated or interpreted from specific geological evidence and knowledge. Geothermal Resources are sub-divided, in order of increasing geological confidence, into Inferred, Indicated and Measured categories.

Any interpolation or extrapolation made to the data for the purpose of making the Geothermal Resource estimate should be clearly stated and described in the Report.

A **'Geothermal Reserve'** is that portion of an Indicated or Measured Geothermal Resource which is deemed to be economically recoverable after the consideration of both the Geothermal Resource parameters and Modifying Factors. These assessments demonstrate at the time of reporting that energy extraction could reasonably be economically and technically justified.

The term 'Geothermal Reserve' need not necessarily signify that plant facilities are in place or operative, or that all necessary approvals or sales contracts have been received. It does signify that there are reasonable expectations of such approvals or contracts. The Competent Person should consider the materiality of any unresolved matter that is dependent on a third party on which exploration and development is contingent.

If there is doubt about what should be reported, it is better to err on the side of providing too much information rather than too little.

Any adjustment made to the data for the purpose of making the Geothermal Reserve estimate, for example assumptions made regarding temperature measurements, should be clearly stated and described in the Public Report.

Certainty of Data

A three stage classification (Inferred, Indicated, Measured) is used to define how reliably a Resource is defined, and two categories (Probable, Proven) for Reserves.

The categorisation indicates to an investor how reliably various parts of any geothermal resource are defined, rather than primarily relying on probabilistic methods using parameter distributions applied to the entire resource to determine categories. However, probabilistic methods can be usefully applied to each category.

Resources

The term 'Geothermal Resource' covers those Geothermal Plays that have been identified and estimated through exploration and sampling and within which Geothermal Reserves may be eventually be defined by reduction of the risk after the consideration and application of the Modifying Factors.

Consideration of the 'technology pathway for usage' at the Geothermal Resource level does not imply actual knowledge or consideration of detailed technology. It is sufficient to consider this in terms of 'ORC binary plant', 'reverse refrigerant plant' or 'flash steam plant', for example.

Documentation of Geothermal Resource estimates should clearly identify any known potential technical risks, including geological factors such as faults which could prejudice production or sources of cool fluid intrusion which could degrade the resource, and Reports should include commentary on the matter if considered material by the persons compiling the Reports.

An **'Inferred Geothermal Resource'** is that part of a Geothermal Resource for which Recoverable Thermal Energy (in units of PJ_{th} or MW_{th}-years) can be estimated only with a low level of confidence. Assumptions made in making the estimate must be stated, especially in respect of the base and cut-off temperatures and the technology pathway for usage. If there is a reasonable basis to do so, convertibility into electricity can be assessed and an additional estimate of the recoverable, converted electrical energy may be stated using units of PJ_e or MW_e-years. The recovery and conversion (if used) factors used must be separately stated alongside the Geothermal Resource figure, whenever it is quoted in a Public Report.

This category of Geothermal Resource is inferred from geological, geochemical and geophysical evidence and is assumed but not verified as to its extent or capacity to deliver geothermal energy. The Inferred category is intended to cover situations where a Geothermal Play has been identified and limited measurements and sampling completed, but where the data are insufficient to allow the extent of the Geothermal Resource to be confidently interpreted. It is based mainly on indirect measurements, for example extrapolation of temperature profiles (to a reasonable degree and on a rational basis) and other associated measurements such as rock properties and heat flow, and requires a reasonably sound understanding of the subsurface geology in three dimensions derived, for example, from geophysical surveys, to indicate temperature and dimensions.

A large fraction of the stored heat contained in the reservoir of a resource will be left in the geothermal reservoir at the time that development ceases. The amount that will be left behind may depend on technical, physical or commercial limitations.

Commonly, it would be reasonable to expect that the majority of Inferred Geothermal Resource estimates would be upgraded to Indicated Geothermal Resource estimates with reasonably proximate drilling. However, due to the uncertainty of Inferred Geothermal Resource estimates, it should not be assumed that such upgrading will always occur.

Confidence in the estimate of Inferred Geothermal Resources is usually not sufficient to allow the results of the application of technical and economic parameters to be used for detailed planning. For this reason, there is no direct link from an Inferred Resource to any category of Geothermal Reserves. Caution should be exercised if this category is considered in studies of technical and economic viability.

An **'Indicated Geothermal Resource'** is that part of a Geothermal Resource which has been demonstrated to exist through direct measurements that indicate temperature and dimensions so that Recoverable Thermal Energy (in units of PJ_{th} or MW_{th}-years) can be estimated with a reasonable level of confidence. Thermal Energy in Place has been estimated through direct measurements and assessments of volumes of hot rock and possibly fluid with sufficient indicators to characterise the temperature and chemistry. Direct measurements are sufficiently spaced so as to indicate the extent of the Thermal Energy in Place. Assumptions made in making the estimate must be stated, especially in respect of the Base and Cut-off temperatures and the technology pathway for usage. If there is a reasonable basis to do so, convertibility into electricity can be assessed and an additional estimate of the recoverable, converted electrical energy may be stated using units of PJ_e or MW_e-years. The recovery and conversion factors (if used) must be separately stated alongside the Geothermal Resource figure, whenever it is quoted in a Public Report.

A Geothermal Play can be classified as an Indicated Geothermal Resource when there has been sufficient drilling into the Play such that the nature, quality, amount and distribution of data allow confident interpretation of the geological framework, the assumption of continuity of the thermal energy distribution and a reasonable estimate of the extent of the Geothermal Play. The well locations are too widely or inappropriately spaced to confirm reservoir continuity but are spaced closely enough for continuity to be indicated.

An Indicated Geothermal Resource estimate has a lower level of confidence than that applying to a Measured Geothermal Resource, but has a higher level of confidence than that applying to an Inferred Geothermal Resource. Confidence in the estimate is sufficient to allow the application of technical and economic parameters, and to enable an initial evaluation of economic viability.

A **'Measured Geothermal Resource'** is that part of a Geothermal Resource which has been demonstrated to exist through direct measurements that indicate at least reservoir temperature, reservoir volume and well deliverability, so that Recoverable Thermal Energy (in units of PJ_{th} or MW_{th}-years) can be estimated with a high level of confidence. The Thermal Energy in Place has been demonstrated to exist through direct measurements and assessments of drilled and tested volumes of rock and/or fluid within which well deliverability has been demonstrated, and which have sufficient indicators to characterise the temperature and chemistry. Direct measurements must be sufficiently spaced to confirm continuity. Assumptions made in making the estimate must be stated, especially in respect to the base and cut-off temperatures and technology pathway for usage. If there is a reasonable basis to do so, convertibility into electricity can be assessed and an additional estimate of the recoverable, converted electrical energy may be stated using units of PJ_e or MW_e-years. The recovery and conversion factors (if used) must be separately stated alongside the Geothermal Resource figure, whenever it is quoted in a Public Report.

A Geothermal Play may be classified as a Measured Geothermal Resource when the nature, quality, amount and distribution of data are such as to leave no reasonable doubt, in the opinion of the Competent Person determining the Geothermal Resource, that the Recoverable Thermal Energy can be estimated to within close limits, and that any variation from the estimate would be unlikely to significantly adversely affect potential economic viability. This category requires a high level of confidence in, and understanding of the geology and heat source.

Confidence in the estimate is sufficient to allow the application of technical and economic parameters and to enable an evaluation of economic viability that has a greater degree of certainty than an evaluation based on an Indicated Geothermal Resource.

Reserves

Only Proven and Probable Reserves should be used when considering the economic feasibility of a project. The process of conducting a feasibility study should refine the assessment of Reserves using more project-specific technical, environmental, regulatory and commercial criteria.

A **'Probable Geothermal Reserve'** is the economically recoverable part of an Indicated or in some circumstances, a Measured Geothermal Resource. It will differ from Proven Geothermal Reserves because of greater uncertainty, usually in terms of factors that impact the recoverability of thermal energy such as well deliverability or longevity of the project. There will be sufficient indicators to characterise temperature and chemistry but may be less direct measures indicating the extent of the Geothermal Resource, within economically feasible drilling depth. Appropriate assessments and studies will have been carried out, and include consideration of and modification by realistically assumed drilling, economic, legal, environmental, social and governmental factors. These assessments demonstrate at the time of reporting that commercial energy extraction could reasonably be justified.

A Probable Geothermal Reserve estimate has a lower level of confidence than a Proven Geothermal Reserve estimate but is of sufficient quality to serve as the basis for a decision on the development of the Geothermal Play. It is 'more likely than not' that the Reserve estimate is correct, reflecting a greater than 50% chance of occurrence.

A **'Proven Geothermal Reserve'** is the economically recoverable part of a Measured Geothermal Resource. It includes a drilled and tested volume of rock within which well deliverability has been demonstrated and commercial production for the assumed lifetime of the project can be forecast with a high degree of confidence. Appropriate assessments and studies have been carried out, and include consideration of and modification by realistically assumed economic, market, legal, environmental, social and governmental factors. These assessments must demonstrate that, at the time of reporting, extraction of the geothermal energy could reasonably be economically justified.

A Proven Geothermal Reserve represents the highest confidence category of Geothermal Reserve estimate. The type of Geothermal Play or other factors could mean that Proven Geothermal Reserve estimates are not achievable in some parts of the Measured Geothermal Resource.

Once a Geothermal Reserve has entered production and some reservoir response can be observed, classification of remaining Geothermal Reserves should become more accurate. Geothermal Reserves under production should be re-estimated with reservoir models re-calibrated to produce new estimates which are more closely linked to observed temperature and pressure changes in the reservoir, and related to the rate of energy recovery achieved.

Proven Reserves should not be solely based on the high confidence limits of a probabilistic estimate based on a larger area of Resource or Reserve that is not so reliably defined. If a correlation is to be made with a probabilistic estimate, Proven Reserves will be conceptually similar to a P90 estimate, but this is not intended to be a rigid correlation.

Information Required for Proven, Probable, Measured, Indicated and Inferred Categories

Different levels of information are required about a geothermal field in order for part or all of it to be classed as Measured, Indicated or Inferred Resources. Additional information regarding commercialisation would need to be included for Probable or Proven Reserves.

Table 1 provides, in a summary form, a list of the criteria which should be considered when preparing reports on Geothermal Resources and Geothermal Reserves. These criteria need not be discussed in a Public Report unless they materially affect estimation or classification of the Geothermal Resources or Reserves. No Guidelines are given for Exploration Results as these could include a wide range of data Sarmiento and Steingrimsson (2007) gave a similar table specific to the high temperature reservoirs in the Philippines. More detail on specific criteria is given in Appendix D.

Changes in economic, title or political factors alone may be the basis for significant changes in Geothermal Reserves and should be reported accordingly.

Table 1. Guidelines for Typical Data to be Considered in Resource Classification

	RESOURCES			RESERVES	
	INFERRED	**INDICATED**	**MEASURED**	**PROBABLE**	**PROVEN**
VOLUME					
Area	Extent of inferred high temperature at selected depth interval based on: ▪ Locations of surface activity e.g. springs and fumaroles ▪ Surface heat flow ▪ Geological analogy in EGS systems ▪ Some geophysical mapping may be available.	Extent of inferred high temperature at selected depth interval based on: ▪ At least one well intercept at Resource depth ▪ Geophysics surveys ▪ Shallow temperature gradients, surface heat flow ▪ Presence of adjacent proven area. ▪ Extent of rock type in EGS systems.	Extent of measured high temperatures in wells at selected depth interval, allowing some zones around wells to be included, and considering well spacing as a guide to confidence that reservoir character is reliably defined.	Extent of inferred high temperature at selected depth interval based on: ▪ At least one well intercept at Resource depth ▪ Geophysics surveys ▪ Shallow temperature gradients, surface heat flow ▪ Presence of adjacent proven area ▪ Extent of rock type in EGS systems.	Extent of measured high temperatures in wells at selected depth interval, allowing some zones around wells to be included, and considering well spacing as a guide to confidence that reservoir character is reliably defined.
Depth	Assessed from hydrology, structure, analogy, geophysical data. Maximum depth expected to be attained by drilling plus reasonable drainage distance (less in non-convective systems).	At least part of reservoir thickness intercepted by a well, possibly extrapolated by geophysics, or adjacent wells. Maximum depth expected to be attained by drilling plus reasonable drainage from deeper (less in non-convective systems).	Maximum depth attained by drilling plus reasonable drainage distance below bottom of well (less in non-convective systems). Governed by temperatures in the outflow area in natural systems.	At least part of thickness intercepted by a well, possibly extrapolated by geophysics, or adjacent wells. Maximum depth expected to be attained by drilling plus reasonable drainage from deeper (less in non-convective systems).	Maximum depth attained by drilling plus reasonable drainage distance below bottom of well (less in non-convective systems). Governed by temperatures in the outflow area in natural systems.
DELIVERABILITY					

Fluid Temperature	Estimated temperatures from surface geochemistry, heat flow estimates and thermal conductivity measurements, geological analogy from offset wells in EGS systems or deep sedimentary aquifers.	Reservoir temperature measured in at least one borehole, lateral extrapolation of known temperatures in conductive systems (less reliable in convective systems) or chemical geothermometry using conceptual hydrological model.	Measured well temperatures or discharge enthalpy.	Reservoir temperature measured in at least one borehole, lateral extrapolation of known temperatures in conductive systems (less reliable in convective systems) or chemical geothermometry using conceptual hydrological model.	Measured well temperatures or discharge enthalpy.
Cut-off Temperature	Minimum temperature required for wells to self-discharge in convective geothermal development. For pumped flows the minimum economic reservoir fluid temperature for commercial energy extraction. Estimate from assumptions on reservoir character.	Minimum temperature required for wells to self-discharge in convective geothermal development. For pumped flows the minimum economic reservoir fluid temperature for commercial energy extraction. Estimate from assumptions on reservoir character.	Minimum temperature required for wells to self-discharge in convective geothermal development. For pumped flows the minimum economic reservoir fluid temperature for commercial energy extraction. Based on measured temperatures.	Minimum temperature required for wells to self-discharge in convective geothermal development. For pumped flows the minimum economic reservoir fluid temperature for commercial energy extraction. Estimate from assumptions on reservoir character.	Minimum temperature required for wells to self-discharge in convective geothermal development. For pumped flows the minimum economic reservoir fluid temperature for commercial energy extraction. Based on measured temperatures.
Base temperature	The lowest temperature that will be reached in the reservoir as part of the extraction process OR a defined Rejection Temperature from a defined power scheme.	The lowest temperature that will be reached in the reservoir as part of the extraction process OR a defined Rejection Temperature from a defined power scheme.	The lowest temperature that will be reached in the reservoir as part of the extraction process OR a defined Rejection Temperature from a defined power scheme.	The lowest temperature that will be reached in the reservoir as part of the extraction process OR a defined Rejection Temperature from a defined power scheme.	The lowest temperature that will be reached in the reservoir as part of the extraction process OR a defined Rejection Temperature from a defined power scheme.

Permeability and pressure	Liquid pressures and permeability inferred from shallow wells or spring flows. Inferred fault or aquifer permeability or proven EGS methodology.	Inferred extension of faults or aquifer permeability, or proven EGS technology. Liquid pressures inferred from wells in adjacent Measured area or shallow wells.	Proven sustained discharge flows from deep well(s).	Inferred extension of faults or aquifer permeability, or proven EGS technology. Liquid pressures inferred from wells in adjacent Proven area or shallow wells.	Proven sustained discharge flows from deep well(s).
Chemistry	No evidence for major problems with fluid chemistry or uncontrollable solids deposition.	No major problems anticipated with fluid chemistry or uncontrollable solids deposition in wells, or in adjacent Measured area.	No major problems with fluid chemistry or uncontrollable solids deposition from fluids discharged from existing wells.	No major problems anticipated with fluid chemistry or uncontrollable solids deposition in wells, or in adjacent Proven area.	No major problems with fluid chemistry or uncontrollable solids deposition from fluids discharged from existing wells.
RECOVERABILITY					
Porosity	Inferred from rock type based on surface mapping, wireline logs, or litho-stratigraphic interpretation.	Inferred from rock type based on surface mapping, wireline logs, or litho-stratigraphic interpretation.	Measured on cores and/or inferred from reservoir transient behaviour, and/or anticipated ability to stimulate in EGS systems.	Inferred from rock type based on surface mapping, wireline logs, or litho-stratigraphic interpretation.	Measured on cores and/or inferred from reservoir transient behaviour, demonstrated ability to stimulate in EGS systems.
Fracturing	Inferred spacing of major fractures and whether regular, localised or fractal in nature.	Inferred spacing of major fractures and whether regular, localised or fractal in nature.	Imaged or deduced from wireline logs.	Inferred spacing of major fractures and whether regular, localised or fractal in nature.	Imaged or deduced from wireline logs.

Commerciality

The second main categorisation is based on whether the energy resource is commercially extractable or not. Developers tend to closely guard their commercial information and like to maintain flexibility to develop fluid extraction and energy conversion systems to meet their business needs over the life of the project. That perspective has to be given due regard as important for project viability. However, an investor needs some certainty as to whether or not the energy is likely to be readily extractable under prevailing typical technical and market conditions (or at least those foreseeable in the short term).

The term **Reserves** is only to be used for those portions of Indicated or Measured **Resources** that are judged by a Competent Person to be economically recoverable with existing technology and prevailing market conditions.

Portions of a Geothermal Play that do not have reasonable prospects for eventual economic extraction must not be included in a Geothermal Resource or Reserve. The term 'reasonable prospects for eventual economic extraction' implies a judgement (albeit preliminary) in respect to the technical and economic factors likely to influence the prospect of economic extraction, including the approximate exploitation parameters. In other words, a Geothermal Resource is not an inventory of all heated areas drilled or sampled, regardless of cut-off temperature[3], likely resource dimensions, location or extent. It is a realistic inventory of those Geothermal Plays, which, under assumed and justifiable technical and economic conditions, might, in whole or in part, be developed.

Typical well deliverability that may be economic for the target method of extraction in the foreseeable future (10 to 20 years) is suggested as a guideline for setting the minimum grade of geothermal reservoir to be considered as any higher category than an Inferred Resource. This eliminates from consideration in Resources or Reserves those heat resources that are too deep or low grade to be considered likely to be extracted with existing or reasonably foreseeable technology.

Typically at an early stage in data acquisition, only an Inferred Resource can be declared. As time goes by and well deliverability is demonstrated, part of the Resource indicated to be suitable to be economically developed now would be regarded as in the Measured or Indicated category, possibly converted to a Reserve if the Modifying Factors can be satisfied, surrounded by remaining areas of lower categories.

The following issues affecting commerciality should be considered in determining whether a Resource or Reserve exists should be considered and where it has materiality, reported on.

Resources

1. There must be a technically justifiable basis for defining the energy in place and the fraction of it that can reasonably expected to be economically extracted (the Resource), which, to be placed in the Measured category, includes having an adequate number of wells to define reservoir dimensions and conditions.
2. An assumption should be made and stated as to a minimum cut-off criterion (comparable to cut-off grade in a mineral deposit). In the case of a stored heat or other lumped parameter assessment the cut-off will be a minimum temperature below which reservoir volumes are not considered part of the Resource. In the case of a numerical simulation it will probably be a minimum well deliverability based on temperature and pressure. This is discussed in more detail below.

3. The cut-off grade for defining the Resource must take into account the limitations of the extraction and conversion technology and explicitly define any assumptions made. This implicitly (and preferably explicitly) includes an assumption about the energy selling price and conversion technology.
4. The potentially very large difference between thermal energy in place and energy that is able to be extracted and converted into a useful form requires that the geothermal code avoid exaggerations of scale of Resources that could easily mislead markets and investors. Resources must therefore, be stated in terms of expected recoverable energy (or *optionally* electricity potentially generated) on the basis of a stated recovery factor and, where used, a conversion efficiency to be applied. In the case of electricity production resources should be stated with reference made to a well-defined technical path for energy conversion, even if this technology is presently un-commercial and unproven.
5. An assumption should be made and stated as to the rate of energy extraction and/or project life.
6. Any material assumptions made in determining the 'reasonable prospects for eventual economic extraction' should be clearly stated in the Report. Interpretation of the word 'eventual' in this context may vary depending on the temperature of the heat involved.
7. If the judgement as to 'eventual economic extraction' relies on untested technology, practices or assumptions, this is a material matter which must be disclosed in a public report (e.g. recovery of supercritical geothermal water).

Reserves

1. The term **Reserves** is only to be used for those portions of Indicated or Measured Resources that are judged by a Competent Person to be commercially extractable with existing technology and prevailing market conditions. For a Reserve to be declared there must be a defined and proven means of extracting the energy and converting it into a saleable form. The differentiation between commercial and sub-commercial is not to be strictly interpreted as implying that commercial feasibility has been demonstrated. Rather it is intended to enable identification of the portion of heat that can be readily extracted using current commercial practices separately from that portion which still requires substantive improvements in technical or cost terms to be viable.
2. The term 'economically recoverable' implies that heat extraction of the Geothermal Reserve has been demonstrated to be viable under reasonable financial assumptions. What constitutes the term 'reasonably economically and technically justified' will vary with the type of Geothermal Play, the level of study that has been carried out and the financial criteria of the individual company. For this reason, there can be no fixed definition for the term 'economically recoverable'.
3. In order to achieve the required level of confidence in the Modifying Factors, appropriate studies will have been carried out prior to estimation of the Geothermal Reserves. The studies will have included resource appraisal work and a development plan that is technically achievable and economically viable and from which the Geothermal Reserves can be derived. It is not strictly necessary for these studies to be at the level of a final bankable feasibility study, but if such has been carried out it is helpful. It is considered sufficient to establish that:
    - an analysis of the economics of the project has been done to a suitable level of detail;
    - the resource parameters and cut-off grades (e.g. technically and economically feasible drilling depth, temperature drop in the reservoir) have been linked to the power cost or price in a technically appropriate way;
    - linkages have been made between the technical uncertainties and the economic sensitivities;
    - there is a reasonable expectation of a market for all production of power at the price proposed, or at least the expected sales quantities of production required to justify development;

- evidence that the necessary route to market, for example transmission lines and access to the grid, are available or there is a reasonable prospect of them being developed;
- evidence that legal, contractual, environmental and other social and economic concerns will allow for the actual implementation of the proposed scheme.

4. The term 'Geothermal Reserve' need not necessarily signify that plant facilities are in place or operative, or that all necessary approvals or sales contracts have been received. It does signify that there are reasonable expectations of such approvals or contracts.
5. Demonstrating the well productivity that can be achieved from the Resource is an essential aspect of securing a Reserve classification.
6. For electricity generation, an assumption must be made and stated as to conversion efficiency to be applied, or reference made to a well-established technical path for energy conversion.
7. An assumption must be made and stated as to the rate of energy extraction and/or project life.
8. Reserves are to be stated in terms of net recoverable and converted energy. If the project is for electricity generation then it should also be presented as net electrical output according to one of definitions in the Glossary.

Cut-off Temperature and Related Criteria

Cut-off temperature is the minimum temperature below which it is not economic to include the reservoir volume as part of the Resource. Therefore it is closely related to the production temperature. The fluid pressure and formation permeability will interact with the fluid temperature to influence deliverability but typically there will be a minimum useful temperature above which energy can be extracted and commercial deliverability can be achieved. cut-off temperature is clearly a function of the total system (well deliverability and temperature and the power plant design) and economic context.

There has been variability within the industry on the definition of cut-off tmperature and the related, but different, concept of base temperature. The scope for variability in approach in defining temperatures to be used in Resource and Reserve estimation is illustrated in Figure 2, representing a well production/reinjection doublet and power plant along with a number of points at which temperatures can be defined. This is discussed further in Appendix A.

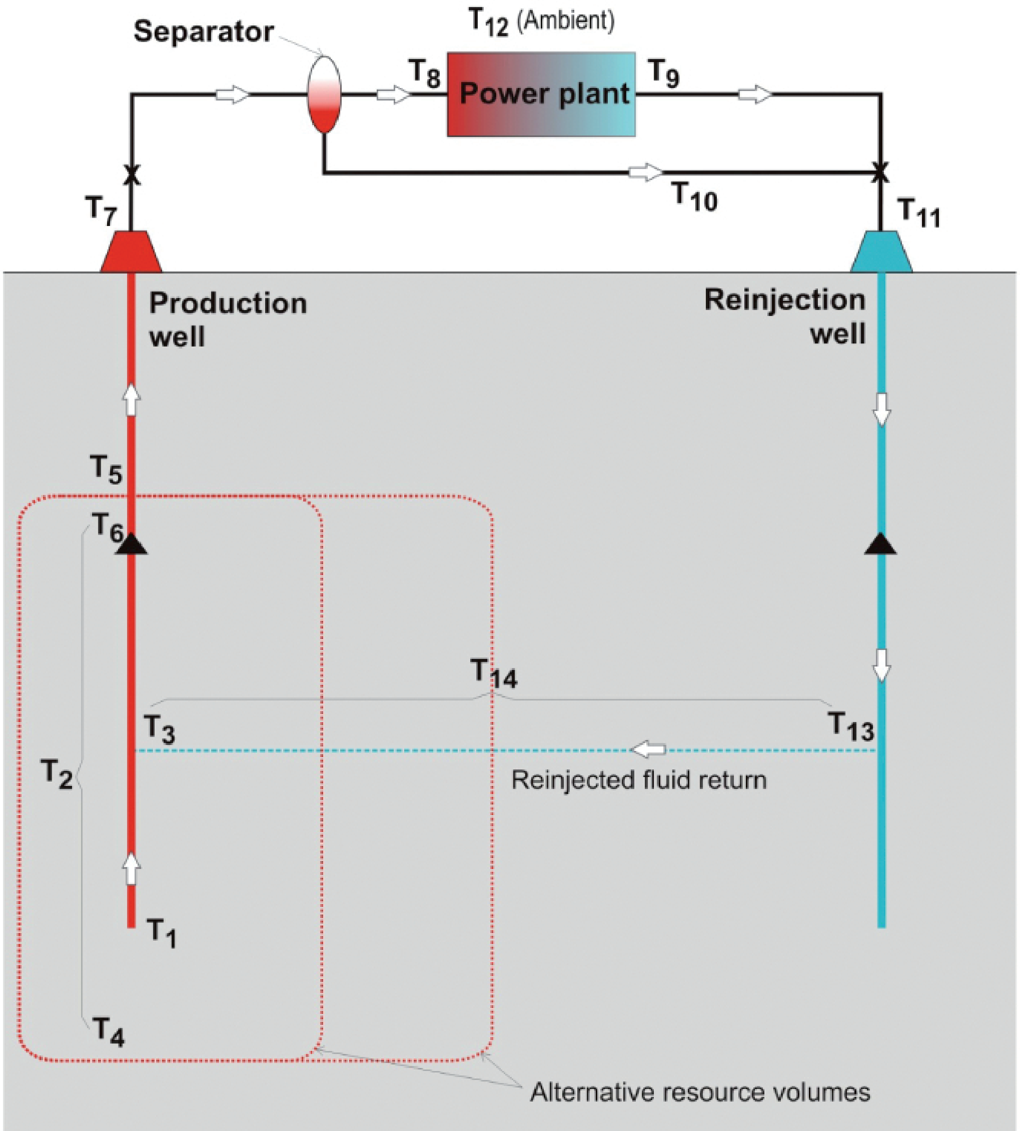

Figure 2: Possible points for temperature definition within a production - reinjection well doublet and power scheme.

The USGS and some other practitioners have previously (Muffler 1979) estimated geothermal resources as all the energy above the local thermodynamic rejection temperature (T_{12} in Figure 2) and then used a recovery factor to estimate the commercially useful heat fraction. This recovery factor rejects both the fraction of heat below the commercially useful temperature and the fraction of unrecoverable heat. Although the USGS has since changed this methodology (Williams *et al.*, 2008) it will still be encountered in older reports so is still relevant.

For the Geothermal Code it is defined that it is more appropriate to first estimate the volume of reservoir from which heat can be extracted, based on a cut-off temperature (T_5), an estimate of the percentage of energy physically recoverable relative to a base temperature, and then to separately allow for an efficiency of converting that into end-user energy (electricity or production heat). The base temperature (T_9 or T_{11}) will be lower than the cut-off temperature, sometimes by over 100°C.

Using the cut-off temperature to exclude the sub-commercial reservoir volume from the Resources and a separate recovery factor to exclude the unrecoverable heat from the Reserves estimation is also more consistent with the SPE/WPC classification.

For non-pumped systems, the limit on the amount of heat that can be extracted from the reservoir is a factor of pressure, flowrate and temperature (enthalpy) of the fluids that will be available to maintain the required flow of self-discharging wells under the designed configuration of production wells, energy conversion plant and reinjection system.

For example, the cut-off temperature for a conventional flash steam plant development should be selected appropriately with regard to the requirements for wells to feed that plant, and unless explicitly included in the total project concept and economics, not assume that pumped wells and binary technology could be utilised later to extract the lower grade residual heat from the resource.

The simplest assumption is that the cut-off temperature is the same as the minimum economic downhole production temperature (T_3 or possibly T_6). However, it is recognised that, with suitable placement of injection, heat at temperatures lower than the well production temperature can be extracted from the reservoir, and in an ideal case, much of the resource will be cooled to injection temperatures before the minimium temperature is achieved at production locations and the heat between injection and production locations will have been extracted by the production wells. It could therefore be appropriate to set the cut off temperature to T_{14}, if suitably justified.

A fundamental criterion in the choice of cut-off temperature (and, by implication the base temperature) is whether the power prices justify pumping. This is providing the temperatures are low enough that downhole pumping is practical: 190°C is currently about the upper limit but the technology is changing rapidly, so it would not be unreasonable in the near future to use a higher figure if technical justification was provided.

Where power prices are low, the cut-off temperature may have to be set at the minimum at which wells will self discharge water and/or steam, which will in turn depend on the depth of the reservoir, its pressure and permeability. In that case there may be a large difference, possibly over 100°C, between the cut-off temperature which determines which reservoir volumes are to be included in a Resource or Reserve, and the rejection temperature from, say, a binary plant which is the basis for the assumed conversion efficiency (T_9, which in that case would logically be used as the base temperature).

For example, in a location with low power prices, a liquid dominated reservoir sector at less than 180°C may have no value as wells will not self-discharge, but fluid that is brought to the surface in other hotter sectors can have energy extracted possibly down to less than 80°C. Where dry steam is present the cut-off temperature may be lower by 20°C or more.

In other locations where power prices justify pumping, portions of the Resource at significantly less than 180°C can be included even if the same base temperature is to be adopted.

If pumping is not to be adopted and where wells are available, such as in Measured Resources or Proven Reserves, then the reservoir and well permeability characteristics should be sufficiently defined to enable a sound and specific assessment of what reservoir drawdown conditions would represent practical minimum limits for well deliverability to be possible. The energy that can be extracted in that case should be based on such assessment using numerical reservoir simulation. In that case the concept of a cut-off temperature has less applicability as it is usual practice to include boundary blocks at less than commercial temperatures within the numerical model. Rather than a single cut-off temperature, assumed permeability and predicted temperatures and pressures are all considered, to produce a prediction of future well deliverability. Wells are assumed to become non-commercial once they diminish to a certain minimum mass flow, wellhead pressure or production temperature. The use of numerical reservoir simulation methods is however only meaningful for Resource estimation once there is a good deal of reservoir information on which to base it.

The conversion efficiency of the plant should represent how efficiently the extracted energy is converted into useful energy.

Whether waste heat is re-injected or not or at what temperature is irrelevant in terms of the conversion efficiency because the main point is how much useful energy is derived from the sum of energy that is extracted from the Resource. Waste heat in terms of heat in the water after energy conversion will be injected back into the reservoir and serves as a means for extracting more energy from the resource and so is factored into the energy extraction part of the process, not the energy conversion. This is discussed further below.

General

Aggregation of Reserves and Resources

Resources and Reserves must not be aggregated and must be clearly differentiated in any statements. Proven and Probable Reserves can be aggregated but must also be reported separately in the same statement. Aggregation of Resources or Reserves should always be to the lower confidence level.

As far as possible the areas of Resource defined by known parameters and reliability of control information should be evaluated separately and then later aggregated appropriately. This is preferable to diluting areas that are truly Measured with broader areas of Indicated or Inferred Resource and attempting to derive reliable definition of Measured/Indicated/Inferred quantities based on probabilistic distributions.

If probabilistic estimations are to be aggregated, they should not be simply arithmetically added. It is necessary to distinguish between independent and dependent probability distributions for different sectors or categories of Resources. If all of the factors in two resources are truly independent, then adding two probabilistic estimates will give a distribution more tightly distributed around the mean than either one individually.

But that will rarely be the case in reality. More complicated situations can occur because some of the underlying parameters may be dependent or correlated. An example of the former would be if a certain permeability distribution in an area is based on the presence of a certain fault, it cannot also be present in an adjacent block. An example of partial correlation would be when considering temperatures on two adjacent blocks: it is unlikely one will fall at the extreme lower end of the possible range and the other simultaneously at the upper end.

The SPE Guidelines (Section 6) give useful advice on how to carry out aggregation of probabilistic estimates. They suggest the use of correlation matrices when aggregating Reserves of the same category to better approximate the real-life situation of partial dependence of variables. When aggregating Resources and Reserves of different categories, they suggest the use of scenario trees.

Area of Influence of Data and Interpolation/Extrapolation

As the rigour of assessment goes up, moving from Inferred to Indicated to Measured Resources, or from Probable to Proven Reserves, so should the degree of interpolation and extrapolation of data go down. It is reasonable to adopt a large degree of extrapolation at the stage of the Inferred Resource, since for example geothermometry from a specific point may in effect be extrapolated to apply to the whole of a geophysical anomaly. In contrast at the stage of Measured Resource or Proven Reserves, the data from each well will be extrapolated to a relatively small volume of the reservoir and there should be a clear basis for such extrapolation, for example the volume determined from microseismic measurements during stimulation in an EGS project.

If there is less variability encountered then more interpolation is acceptable. Those relationships could be quantified geostatistically though the number of data points such as temperature in a geothermal development will usually be too small for a rigorous analysis, compared to the typical situation in a mineral deposit.

The degree of interpolation and extrapolation that is appropriate depends on the nature of the geothermal play, which must be assessed in terms of an appropriate conceptual model. The key to appropriate resource estimation is to develop and keep refining a conceptual hydrological model of the geothermal play which makes use of all available data (Bodvarsson *et al.,* 1986). Often data from one discipline can complement those of another in a way that may not be apparent until they are combined. For example, if relict hydrothermal alteration is found on the surface, it could mean that some of the zones of low resistivity are likewise relict. In this case it means that the size of the Indicated or Measured Resource can be no larger than the available geophysical anomaly, and may be considerably smaller.

Generally speaking natural convective geothermal systems will be less uniform than EGS plays and deep sedimentary aquifers, because their more vigorous fluid processes will give rise to sharper temperature and chemical gradients both laterally and vertically. In EGS and some HSA projects it is likely that the depth of production and injection wells will be the same and the production and reinjection wells will be interspersed. That is unlike the situation in conventional volcanic-hosted geothermal projects where production and reinjection wells are usually separated into discrete sectors. Therefore in EGS and deep aquifer projects the reinjection wells will yield just as much information on reservoir properties for production as do the dedicated production wells.

Each well yields information on a certain volume of the play. At one extreme, the Area of Proven Reserves could be regarded as fully defined when production and reinjection wells are drilled across the entire area to be utilised at close to the final spacing for development, but that is clearly excessive. Deciding how many wells are needed to define the Resource requires a subjective assessment of what area or volume of the reservoir can be regarded as verified by each well.

Nor are all wells equal. A common strategy once the initial discovery has been made is to drill wells located more towards the margins of the reservoir then to fill in the gaps. By doing so, the Reserves will increase rapidly at first, and then follow an S-shaped curve with time. By following this approach the reliability of the Reserves assessment will also increase with time, but more slowly than will the quantum. If the Reserves were being assessed on a probabilistic basis that would be reflected in the numbers.

There will also be some step-changes in the Reserves or Resources estimate when certain events occur such as the drilling and testing of the first well to the full proposed total depth, or verification of the power plant technology.

At the stage of Resource definition, these aspects can be more readily dealt with by reference to the conceptual model and making justifiable assumptions. At the Reserve definition stage the suggested approach is to quantify the volume of influence of information from each well in terms of the key reservoir parameters.

In a natural convective geothermal system those are:

- Temperature and enthalpy and their distribution laterally and vertically. For a laterally extensive resource it is probably best to look at the anticipated lateral temperature gradients and assess how the wells have delineated the ranges in temperature. Extrapolation and interpolation of vertical temperature gradients must be done with caution, and the presence of two-phase zones taken into account.
- Pressure. Pressures can more reliably be extrapolated, but once again the presence of two-phase zones must be taken into account.

- Fluid chemistry. This must be related to the conceptual hydrological model of the system. For example, the model may lead to recognition of discrete secondary acid zones, which may be able to be avoided.
- Permeability, both at the level of the whole reservoir and at the level of individual well deliverability.
- Effective porosity including both pores and fractures.

For HSA projects the list of parameters will be much the same, though perhaps simplified through greater lateral uniformity and a lack of two phase zones.

For EGS systems the same applies and in the case of HR systems fluid chemistry is less important. In HR systems with consistent rock type, a one-to-one correlation can be expected between the fluid chemistry and temperature.

Other factors which have to be considered in the case of EGS projects are stress regime and rock properties that impact the ability to stimulate or otherwise create a productive reservoir.

In EGS systems, development of a permeable reservoir is critically dependent on being able to induce new fractures or open existing fractures in the rock, and the orientation, spacing and continuity of those fractures. Because of the geological uniformity it can be expected that a similar stress field will persist laterally over a considerable distance, but it is possible that unknown geological discontinuities such as faults could disrupt that simple pattern. A reliable estimate of the minimum area of influence of each well laterally in this respect can be obtained from the lateral extent of acoustic events detected during fracturing. It is not necessary to drill out and fracture the full lateral extent of the reservoir to verify the stress regime. Interpolation is clearly reasonable provided that there are no intervening major structures, and some extrapolation is reasonable. Extrapolation of stress regimes should be guided by confidence in understanding major structures, but in general it would be unwise to assume that the same situation can be extrapolated to much greater than the drilled depth both because the stress regime may change with depth and because there could be practical difficulties in achieving fracturing in deeper/hotter wells. That is especially the case if future projects extend to temperatures above the brittle-ductile transition for typical reservoir rock such as granite.

With regard to temperatures at greater than drilled depth, in non-convective systems some extrapolation is considered justifiable for Resource estimation at least, provided there is a reasonable basis for assuming heat flow, geology and rock thermal conductivity. For Reserves estimation in EGS and HSA projects it is considered that at least one hole should be drilled to full depth, but the temperature gradient (not the absolute temperature) measured within the reservoir in that hole can then be taken as applying over a wide area.

Methods of Resource Estimation and Their Applicability

At different stages of a geothermal development the methods used to estimate the geothermal Resources and Reserves will vary according to the available information. A variety of methods has been previously used for assessing energy that can be extracted and include:

- estimation of natural heat flow representing long term sustainable energy available;
- analogies based on other fields that have been produced for a long period;
- summing outputs from existing wells;
- volumetric assessment of heat in place and the portion that can be extracted;
- lumped parameter models;
- well decline analysis;
- numerical simulation reservoir models.

All of these have been applied deterministically or through some form of probabilistic approach but most have weaknesses or limited applicability. In summary:

- Assessing available energy output based on surface heat flow only is likely to lead to an unrealistically low number for the physically sustainable extraction rate over a typical project life.
- Using summation of well outputs alone is not at all definitive and only has any useful application for resource estimation if sensibly combined with well decline analysis based on a suitable history of well performance.
- The analogy method has usefulness for the early stages of exploration, but should not be used for anything more definitive than Inferred Resources.
- Well decline analysis is likely to be useful only in special circumstances, in projects with a long production history and where the current production/reinjection regime is expected to continue unchanged.
- Only the volumetric methods and numerical reservoir simulation are adequate for the purpose of defining Proven or Probable Reserves.

However, using an overly-complicated method too early in the exploration process can lead to spurious precision. It is perfectly possible to carry out a numerical reservoir simulation before any data is available from drilling, but it is usually of little value for resource definition (Parini and Riedel 2000) and can be actively misleading.

Wherever possible these methods should be applied (and their sensitivity tested) with consideration of the classifications of Resource category as defined in the Code. Ideally, the industry should continue to use several methods in parallel and through sharing experience (via publication) improve understanding of when each method is applicable and obtain control on how they differ in reliability.

In this section the various ways in which geothermal Resources can be quantified are described in general terms and their applicability at different stages of the exploration process considered. That is summarised in Table 2 according to the stage, and the following text follows a sequence from early exploration to development and on-going operation.

Table 2: Methods of Resource Estimation and Their Applicability

	Applicable						
	Early Exploration (pre drilling)	**Exploration**	**Delineation**	**During production**	**Expansion Phase**	**Resources**	**Reserves**
Surface heat flow	Yes, but low confidence	Yes, but low confidence	Largely redundant	Redundant	Redundant	Yes, Inferred, to a minimum	No
Sum of existing well outputs	N/A	No, does not directly indicate resource capacity	No, does not directly indicate resource capacity	No, does not directly indicate resource capacity	No, does not directly indicate resource capacity	No, except for very short term	No
Analogy based on area	Yes, but low confidence	Yes, but low confidence	Largely redundant	Redundant	Redundant	Yes, Inferred, but low confidence	No
Stored heat	Yes, but low confidence	Yes, preferred method	Yes	Largely redundant	Largely redundant	Yes, Inferred, Probable or Proven if backed up by well deliverability	Yes, Probable or Proven if backed up by well deliverability
Lumped parameter models	Yes, but not advisable	Yes, but not advisable	Yes	Yes, in some cases	Yes, in some cases	Yes, Inferred, Probable or Proven if backed up by well deliverability	Generally no
Decline curve analysis	No	No	No	Yes	Yes	Yes, Inferred, Probable or Proven, but not favoured	Generally no
Numerical simulation models	Yes, but not advisable	Yes, but not advisable	Yes, but low confidence	Yes, preferred method	Yes, preferred method	Yes Inferred, Probable or Proven	Yes, Probable or Proven if backed up by well deliverability

Heat Flow

It is possible to estimate the total surface heat output of a convective system at the surface, in MW thermal (MWth) units, based on a combination of spring flow estimates and temperatures, heat emission from hot ground and estimates of steam flow from fumaroles. The latter is the most difficult to estimate and makes a substantial contribution to the heat flow, which makes the accuracy of the estimates low in some cases.

As a cross-check it may be possible to estimate the total chemical flux through the system. For example, several of the large geothermal systems in New Zealand are located adjacent to large rivers or lakes, to which the surface thermal features drain. By measuring the chloride content of the river upstream and downstream of the thermal area, and the flow rate of the river, it is possible to estimate the total chloride flux through the system. This has the advantage of picking up the contribution from minor thermal features which might otherwise be overlooked, and from shallow subsurface flows to groundwater, which can be substantial. One can then assume a chloride content and enthalpy of the deep fluid supplying the chloride and heat, and estimate the heat output on that basis.

Where the surface activity consists mainly of outflowing primary chloride springs, the heat output from the springs gives a good estimate of the *minimum* natural heat flow through the system. However, where the thermal activity consists mainly of steam-heated springs or fumaroles which appear to be derived from a shallow steam zone, it is reasonable to infer a much larger subsurface mass flux through the system (and so a greater heat flux), as only a portion of the fluid reaches the surface. It is possible to estimate this by assuming a reasonable deep fluid enthalpy based on chemical geothermometry, and a flashing temperature to supply the thermal features.

To use the heat flow for a resource estimate, the principle is to take the minimum natural heat flux from the system, whether derived from physical estimates or chloride flux, and assume that this is the absolute minimum heat output that could be produced from wells, then apply a conversion efficiency to electricity - say 10% in the absence of a defined project concept. In practice, this estimate is normally unrealistically low. Some fields have little or no surface expression (e.g. Desert Peak, Nevada). It may be possible, based on experience, to develop a factor that allows a more realistic estimate to be obtained (Wisian *et al.,* 2001). But in fields which have either very little or very significant thermal activity, a different factor should be used. Sanyal and Sarmiento (2005) concluded that a range from 5 to 25 times the natural heat flow is appropriate in non-sedimentary reservoirs and an even larger range for sedimentary systems.

In naturally convective systems this method can serve as a sensibility check on other methods, but it is highly dependent on the hydrology of the system and it will only ever give a minimum which may bear little relation to the real long term production potential.

This method should not be applied to HSA or HR systems.

Areal Analogy

This is an empirical method based on analogy. An estimate of the areal extent of the resource is multiplied by a power density factor expressed in MWe/km^2. The power density factors are based on experience in other geothermal fields with similar characteristics. When looking at previous estimates or existing projects it is necessary to distinguish between extraction from the borefield, which might be quite a small part of the geothermal system, and extraction from the total field area, as past analysis have used either.

Various opinions have been expressed as to an appropriate level of power density. Donaldson and Grant (1979) suggested 10 to 11 MWe/km^2 was appropriate for Wairakei, based on total field area, and this was supported by Allis (1981). McNitt (1978) stated that a reasonable average for water-dominated fields is 60 MWe/km^2, based on *borefield* area. Grant initially (1996) suggested 10 MWe/km^2 as an average of flashed steam plants and later (2000) suggested if using a wider variety of technology a range of 8 to 30 MWe/km^2 might be appropriate, correlated with temperature (Figure 3), but his data show considerable scatter indicating other factors are important. A similar analysis with more data by Sanyal and Sarmiento (2005) showed no correlation and they suggested reservoir thickness and recharge were the two big unknown factors affecting the outcome. Sanyal proposed a variation of this technique using reservoir simulation to estimate the natural state recharge as a basis (Sanyal, 2005) but this requires deep drilling information to calibrate the model, by which stage more sophisticated methods are probably more applicable.

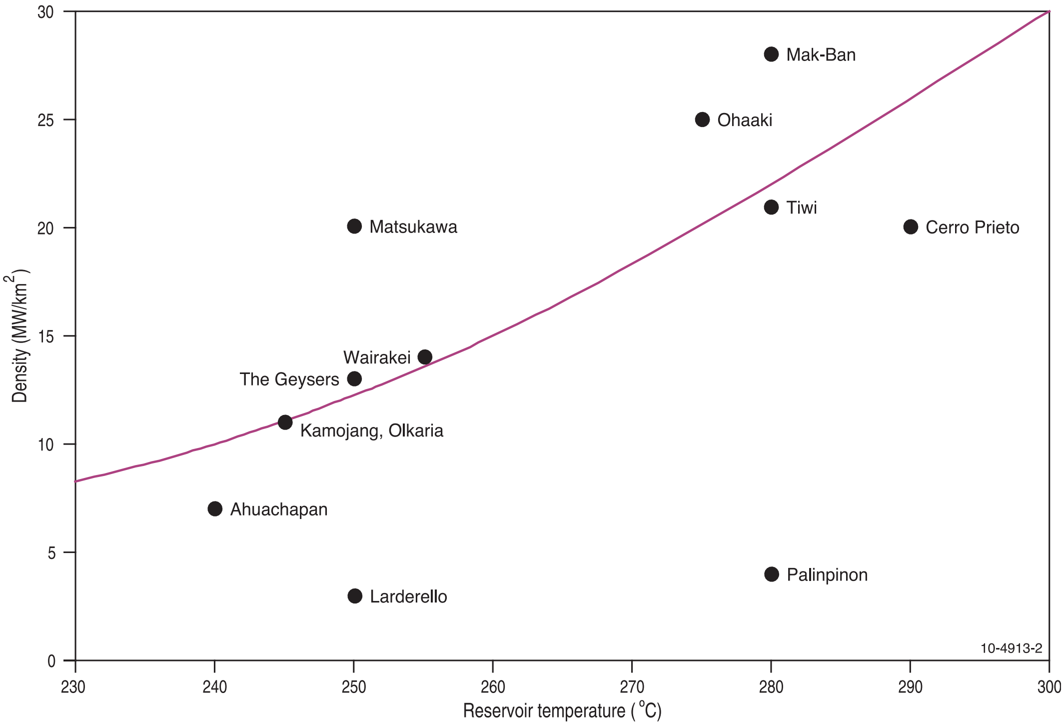

Figure 3: Electrical Energy Power Density for Developed Fields, after Grant (2000), with best fit curve added.

It is suggested that for natural convective systems an initial estimate of sustainable output should be 10 MWe/km^2 (excluding outflows), based on total field or resource area. This can then be up-graded or down-rated depending on field-specific factors, such as indications of abnormally high temperatures, indications of low or high permeability or high wellhead elevations with respect to the resource. An upper limit for liquid-dominated systems would probably be 20 MWe/km^2. In high enthalpy two-phase or steam dominated fields with good permeability, the sustainable rate of production may be as high as 25 MWe/km^2, but it would not usually be prudent to assume that this applies prior to drilling.

This method is in effect a sub-set of the volumetric methods, using a single fixed set of parameters apart from area. The method has not been recently re-calibrated to reflect changing energy conversion efficiencies.

Refinements can be made to the areal method by dividing the field into potential development sectors based on the terrain and realistic limits of directional drilling, then giving priority to sectors which access large areas of resource, but that level of refinement is probably better done using the volumetric method.

It is not recommended this method be used to any greater precision than for Inferred Resources. Its greatest value is perhaps to give a rough rule of thumb when scoping a project.

Aggregation of Well Outputs

A simple approach is to sum the measured outputs of the wells drilled during exploration. A certain minimum 'power at wellhead'—say 50% of the total required for generation—is sometimes used by investors as a criterion for financial closure. It has some appeal in that it is easily measured and confirms that there is a certain probability of the project achieving what it was designed to do on day one. It is not however a good basis for assessing long term reservoir response and hence Reserves. It needs to be backed up by another method which takes a longer term view and as a minimum requires combination with some assessment of well decline over time, as it does not include the following factors:

- There is no allowance for well or reservoir run-down over time.
- There is no allowance for interference between adjacent wells, which can be significant. Thus the sum of the wells tested individually may not be the same as the total output of the wells when flowed together, even initially.
- There is no consideration of injection capacity. Some fields can be injection-limited rather than production-limited.

Volumetric Methods

Volumetric resource estimation is most commonly used in the later stages of geothermal exploration after drilling has started, although it may be used earlier if good surface indications and geophysical surveys are available. Volumetric stored heat estimates are well established within the geothermal industry. It is considered by many that volumetric estimation is the only one of the methods consistently applicable for resource estimation at an early stage of knowledge (Sanyal and Sarmiento, 2005).

This method is applicable to both convective and conductive resources, though the recovery factors to be applied may be very different in those two situations. In the case of natural convective systems, volumetric methods may underestimate resources because commonly no account is taken of recharge.

Categorisation of Resources and Reserves applied to different sectors will require the appropriate selection of parameters for deterministic or probabilistic estimates of energy available from each area. This also encourages banding according to known resource quality variations such as temperature as it varies from the centre to the margins of a resource.

Provided it is used for this purpose and the limitations are understood a stored heat assessment can be very helpful. When done in a deterministic manner for Inferred Resources it should not be regarded as any better than ± 30 % for stored heat, perhaps ± 50% in terms of generation capacity, and possibly much less accurate in some cases.

For regular updating of Reserves in a developed field, or for estimates based on fields that have some history of production the conventional stored heat calculation is not adequate. Dynamic changes (observed or predicted) need to be accommodated in the assessments or included within more sophisticated numerical models.

Consideration of Dynamic Changes

Geothermal systems differ significantly from mineral and petroleum resources because they are continually being replenished by an on-going flow of heat from depth by conduction or by convection of water, albeit at widely varying rates. Some quantification is given by Rybach and Mongillo (2006).

Conductive heat flow from outside the resource volume assessed is generally too slow to make much difference on a human time scale, and so this aspect can probably be neglected in EGS projects, unless there is a clear source of enabling permeability, but convection can make a significant difference in systems with high permeability. In laterally extensive sedimentary aquifers, even with full reinjection, pressure drawdown due to cooling could induce considerable lateral recharge and maintenance of heat and fluid, albeit presumably with fluid which is not much hotter than that originally in place.

The heat and fluid recharge rate and its effect on resources is usually poorly defined during the early development stages of a project, and so has often been ignored. If it is to be included, then the evidence for quantifying the recharge and the method of inclusion in the reserves must be stated clearly. At the pre-production stage such evidence would have to include at least surface heat flow measurements to be credible.

At a later stage in development, after production and reinjection have started, the Resources or Reserves are influenced by the performance of the wells and especially by the hot and cold recharge to the reservoir. Traditionally, stored heat assessments have ignored recharge as this is believed to yield a conservative estimate of the Reserves. On the other hand it is a moot point whether in fields with a long production history the heat already extracted should be subtracted from the stored heat assessment.

Experience in natural geothermal systems such as Wairakei-Tauhara (New Zealand) and Nesjavellir (Iceland) has demonstrated that in favourable situations recharge can supply a substantial proportion of the heat extracted and can extend the productive life of the resource.

On the other hand, there are a number of fields including Ohaaki (New Zealand) and Tiwi (Philippines) where the resource has been down-graded by ingress of low temperature groundwater cooling part of the high temperature rock. These issues are discussed further by Clotworthy, Lawless and Ussher (2010).

Reservoir Modelling Methods

'Reservoir Modelling' covers a wide range of activities, all aimed at understanding and predicting the dynamic behaviour of geothermal systems. Many different methods have been applied, from relatively simple analytical and lumped parameter models to sophisticated 3-D numerical models that include heat and mass transfer and phase change.

Lumped Parameter Models

In lumped parameter modelling, the geothermal system is essentially treated as a single element with average reservoir properties. In its simplest form, the model can therefore be viewed as a closed tank from which production is occurring, and pressure decline will therefore be a linear function of cumulative production. It is possible by using the principles of superposition in space and time, to define boundaries in the system and to include time varying production and/or injection flows. Further sophistication can be added to include particular relationships between recharge and pressure decline.

The methods used to analyse pressure transient test data from geothermal wells can be used to determine how the reservoir will react, in terms of pressure change, to production and injection. This technique is generally referred to as 'Analytical Modelling'. This technique is most often used in fields where only single-phase water is present. It can also be used in vapour-dominated systems with relatively minor modifications.

In setting up the analysis methods, the following simplifying assumptions are usually made, which must be borne in mind when using this technique in geothermal fields:

- Darcy's Law applies (flow in the reservoir is laminar);
- porosity, permeabilities, viscosity and compressibility are constant;

- fluid compressibility is small (basic method is not valid where steam or two-phase conditions are present);
- pressure gradients in the reservoir are small;
- flow is single phase;
- gravity and thermal effects are negligible.

When analysing pressure transient data, the intention is to determine the reservoir transmissivity and storativity based on the measured pressure response to production, injection or a combination of both. In contrast, the intention with analytical modelling is to calculate the pressure response in the reservoir and/or wells to an assumed production scenario. The transmissivity and storativity then become input variables. These may not be well defined and it may therefore be useful to conduct a sensitivity study to determine the impact of changes in these variables.

Lumped parameter models have been fairly widely used to study field responses to production, both at the pre-exploitation stage (Grant, 1979a) and after the impact of production has been measured (Gudmundsson *et al.*, 1985). Models have also been used to investigate changes, such as injection returns, that may be occurring within a field or well (Harper and Jordan, 1985; Malate and O'Sullivan, 1990a). However in most cases lumped parameter models are inferior to numerical simulation models for the higher categories of Resource or Reserves definition (Sanyal and Sarmiento 2005).

Decline Curve Analysis

With decline curve analysis, the purpose is to determine how the flow rate will change with time in a particular well or over a field as a whole. It is basically a curve matching method where the known production decline is fitted to a defined equation and the equation is then used to forecast future production; in geothermal reservoirs, the decline is normally assumed to follow either 'harmonic' or 'exponential' decline trends. As it is a curve matching method, it is generally used as an assessment tool during the production stage. It can also be used prior to production to help determine make-up well requirements for various assumed decline conditions.

The harmonic and exponential decline trends are defined by the following equations:

$$W = \frac{W_i}{1 + D_i \Delta t} \text{ (harmonic decline) and } W = W_i \cdot e^{-D\Delta t} \text{ (exponential decline)}$$

where:

where:	W	= flow rate at time Δt
	W_i	= initial flow rate at time zero
	D_i	= initial harmonic decline rate
	D	= constant exponential decline rate

It is difficult to distinguish between harmonic and exponential decline at short production times but the distinction between the trends become clearer as the production time increases.

Although the method is empirical, it has proven to be popular in vapour-dominated systems, such as The Geysers, California (Sanyal *et al.,* 1989). In The Geysers it was found that the production decline in individual wells may initially be exponential but with increasing time, the decline trend changes and approaches harmonic decline. The method is also used routinely for providing short term forecasts of flow rate decline in Cerro Prieto, Mexico.

However the method is not necessarily suitable for long term Reserves estimation because it implicitly assumes field management practices will remain unchanged. In the case of The Geysers, recent injection of large quantities of make-up water has significantly shifted the rate of run-down. Field wide modelling at The Geysers in 1993 (Pham and Menzies, 1993) indicated that the field was likely to have a long term decline trend close to 9% harmonic: by 2002 that had changed to 3% because of management changes (Sanyal *et al.,* 2000).

Numerical Simulation Models

Numerical simulation modelling basically involves dividing the reservoir into a series of blocks, and then calculating the behaviour of the geothermal system as fluid flows through the blocks in response to natural or induced pressure gradients. This technique is more sophisticated than the methods described previously as it is possible to have different rock and fluid properties within the model, to include heat and mass transfer between various areas of the model and to include phase change from water to steam and vice versa. The more sophisticated models may also include the effects of gas and dissolved solids on the thermodynamic and physical properties of the fluid.

In order to solve the required equations, it is necessary to use numerical methods and to iterate until a solution is obtained that fits the internal conditions in the model and the boundary conditions. A number of computer codes are now readily available that can provide the required results, e.g. TOUGH2, TETRAD and for single phase systems modified groundwater models may be useful.

The level of sophistication of numerical simulation models can vary over a wide range; from simple 'tank' or lumped parameter models with only a few blocks, through to detailed 3-D models with many thousands of grid blocks. The simple tank models are similar to those described earlier but by solving the equations using numerical techniques, it is possible to include phase changes, etc. which cannot be accounted for using analytical methods.

At the exploration stage, when limited data are available, numerical simulation is unlikely to give a more realistic estimate of long term capacity than simpler volumetric methods. Numerical simulation can still be of value at that stage, but it may be best aimed at answering specific questions to gain insight into the resource rather than necessarily predicting the long term behaviour of the reservoir under exploitation. Examples of the type of questions that could be addressed during the exploration/delineation stage might include the following:

- How close can wells be spaced to avoid undesirable interference?
- How rapidly will cold groundwater penetrate laterally or vertically into the reservoir?
- How rapidly will injected fluid return to production wells (though reservoir modelling will not be able to predict the occurrence of unknown specific paths of high permeability such as faults)?
- At what rate of exploitation/injection will a liquid reservoir become two-phase?
- How fast will the liquid level under a steam zone drop during exploitation?
- Will shallow steam zone pressure increase to the point where there is an increased risk of hydrothermal eruptions?

It is therefore more applicable at this stage to investigating possible constraints to development than resource estimation as such.

Numerical simulation modelling starts to become of real value during the appraisal and detailed design stages when numerous wells have been drilled and tested to provide realistic constraints on the model parameters, and later when projects are being optimised.

The value and confidence of numerical simulation models takes a major leap as soon as long term production starts and data become available on the reservoir response. Even six months of history at a modest rate of production may be sufficient to calibrate the numerical model so it can start to provide reliable estimates of long term performance under various development scenarios.

To be able to do that two conditions have to be fulfilled:

1. The reservoir has to be placed under sufficient stress to cause a measurable response. If the first stage of development is so small it causes no detectable effects on the reservoir, then it is reasonable to predict that the same level of production can be sustained for a long period of time, but it does not assist much with calibrating the model to predict the effects of a greater level of development. This was a significant issue with the Ngawha project in New Zealand, for example (Lawless *et al.*, 2006).
2. There must be sufficient high quality data from monitoring to understand the reservoir processes. Many reservoir simulation models are capable of predicting physical behaviour of fluids with a high degree of complexity and apparent precision, but are poorly geologically and geochemically constrained. Some of the essential data required for that purpose are obvious: downhole pressure measurements and well flow data (mass outputs, enthalpy, injection flows) would be collected by any prudent operator. Others are less routinely collected but can provide great value in interpreting reservoir changes, hence calibrating the reservoir model, leading to an increased reliability of the reserves estimate. These include:
   - well chemistry;
   - changes in surface thermal activity;
   - repeat microgravity surveys combined with precision levelling and groundwater measurements;
   - microseismic monitoring.

Reservoir simulation is the most applicable method for estimating remaining Reserves for geothermal fields under production. A detailed reservoir modelling study used for long term Reserves estimation should comment on the level of monitoring which has been carried out and the conclusions drawn from it.

Reinjection Short-Circuiting

There are geothermal fields where reinjection wells have lead to short-circuiting of low temperature injectate, which has depleted the Resources and Reserves by prematurely cooling part of the reservoir below the commercially viable cut-off temperature. This can be a major problem in some volcanic hosted geothermal projects (e.g. Hatchobaru in Japan) with localised high permeability. The re-circulated fluid is cooler than desired, and heat is only extracted from a fraction of the reservoir volume reducing the recovery factor. This is not an issue that can always be resolved by reservoir modelling since it is dependent on the occurrence of specific geological structures, the location and number of which cannot readily be determined in advance of drilling. In other words, it is certainly feasible to model best and worst case situations (e.g. Bodvarsson and Tsang, 1982) but reservoir modelling does not necessarily give any insight into which is more likely to occur, at least until there is some production history to match it to.

Given the expected more uniform geology of HSA, HDR and HFR reservoirs, short-circuiting is probably less likely to occur than in a natural volcanic hosted reservoir, provided that wells are sufficiently widely spaced. It does remain an issue especially if geological discontinuities such as faults are encountered. The degree of anisotropy of acoustic events observed during fracturing may give a clue as to how likely it is to occur.

In both natural and EGS systems tracer tests can be helpful to assess the degree of anisotropy of permeability and hence the likelihood of reinjection short circuiting. Results obtained before full scale production and reinjection start may however not correspond well to what happens when there are later larger pressure disturbances and thermal effects.

How much does this matter to Resources and Reserves? The possibility that this would affect so many wells as to make the project non-viable seems unlikely. It is therefore not a potentially fatal constraint that has to be resolved before any Reserves can be declared. If it does affect some wells, the implication is that a greater reservoir area will be needed, and there will be extra cost in drilling new wells. It may be a reason for Reserves to be temporarily reduced until replacement areas can be proven, or wells may be constructed to enable downhole zonal flow control if these risks are foreseen.

Probabilistic Assessment of Resources and Reserves

Probabilistic methods provide a structured approach that accounts for both the uncertainty in each of the parameters that affect reserves of individual development and production. Probabilistic methods help ensure that quoted quantities are appropriate relative to the requirements of certainty. Note that probabilistic models are designed to model *variability* of parameters, but do not represent the *completeness* of the construct (there may be a feature that is not recognised and therefore is not represented).

The **stored heat** method is well suited to being adapted to a probabilistic approach. The basic method uses a 'deterministic' approach to the estimation of resources and reserves, which means that each variable is assigned a fixed value. In practice, it is more meaningful to allow the variables to vary over a defined range, with the probability of any particular value being determined from an appropriately defined distribution. This is the basis of the 'Monte Carlo Simulation' technique. A good summary of the application of the method to geothermal stored heat assessments is given by Sarmiento and Steingrimsson (2007).

Using this technique, a random number is first generated and then used with the defined probability distribution to determine the values of the variables. The stored heat is then calculated using the generated values. This process is repeated until a well defined probability distribution for the stored heat, recoverable energy or power output (MWe) can be generated. In practice, it is normally necessary to repeat the calculations more than 2,000 times to obtain reliable and reproducible results.

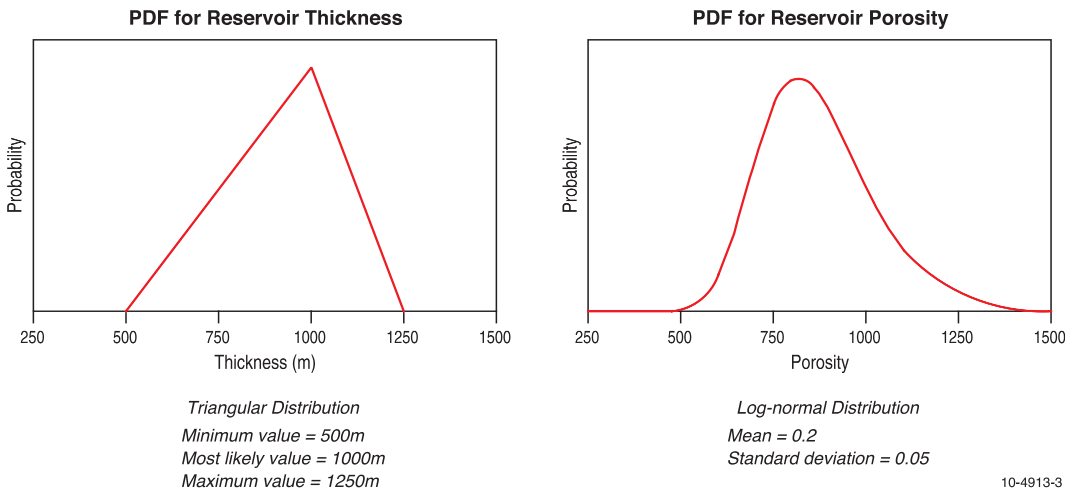

Figure 4: Examples of Triangular and Log-Normal Distributions

There are a large number of possible probability distributions that can be used to describe each of the variables. The most popular distributions, however, are the triangular and log-normal distribution (Figure 4) as they can be 'skewed' to various degrees. In the triangular distribution, minimum, most likely and maximum values are used to define the distribution. For example, the reservoir temperature may be described in this way to be consistent with a similar distribution of reservoir area. For the log-normal distribution, the mean and standard deviation need to be defined.

The results from a Monte Carlo Simulation are generally presented as a histogram of number of occurrences of a particular value (Probability Density Function - PDF) and as a plot of the Cumulative Distribution Function (CDF); examples of these plots are shown in Figure 5. In this particular case, the most likely value occurs at 100 MWe. The CDF plot shows that the probability that the field size is *less than* 100 MW is 0.45 or, conversely, there is a probability of 0.55 that the field size is *greater than* 100 MW. The *median* value occurs at a cumulative probability of 0.5 and is 105 MW, in this case. Terms such as 'P50' or 'P90' may be used for the value at the 50th or 90th percentile.

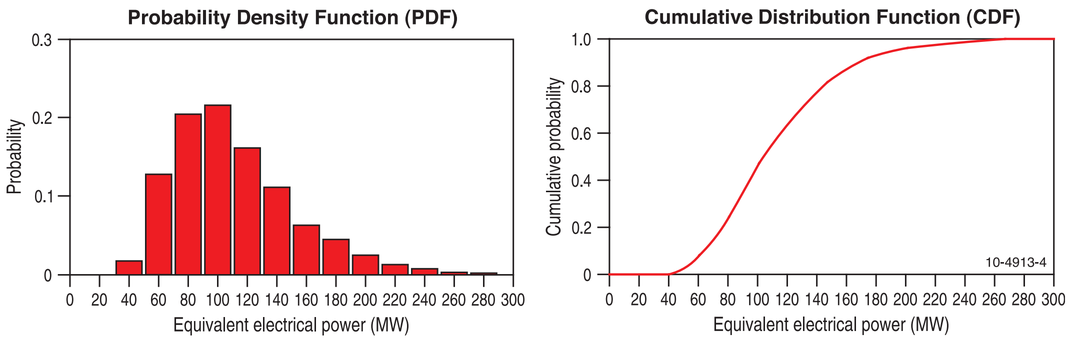

Figure 5: Monte Carlo Simulation Results

The SPE Guidelines make the following important point with regard to assigning probability distributions which is just as valid for geothermal as for petroleum:

"The pdfs selected should reflect available observations and interpretations. Particular care is required to ensure that an appropriate (and realistic) range is chosen. For example, it is frequently overlooked that the pdf for a reservoir property such as porosity defines the uncertainty in the estimate of the average porosity, which is not the same as the actual range of porosity values encountered in the reservoir. The complete distribution from P100 (minimum) to P0 (maximum) should always be viewed to ensure that it represents a valid range of uncertainty for that parameter."

They also offer the following useful advice:

- *"The pdf of a sum of a large number of independent quantities of the same magnitude tends toward a normal distribution. Examples are the reserves of a large number of equally sized fields in a portfolio, and the porosity of a rock body. If they are not of the same magnitude, the sum and its pdf will be dominated by the largest ones.*
- *By the same token, the pdf of a sum of logarithms tends toward a normal distribution. As a result, a product of independent factors, whose logarithms are of the same magnitude, tend toward a log-normal distribution. Examples of entities that are strongly affected by products are the reserve of an accumulation and the permeability of a porous system.*
- *The normal, log-normal, or other appropriate distributions must only be applied to the extent that, and in the intervals for which, they usefully reflect the underlying uncertainty. For instance, when a distribution contains negative values or extends to infinity, and the quantity described definitely is positive and bounded, the distribution will have to be modified to fit reality."*

A **numerical reservoir model** as usually applied provides a deterministic estimate of the resource or reserve, although in some fields multiple model runs have been used for probabilistic assessments. That is intrinsically much more complicated than for a stored heat estimate, because of the much larger number of variables involved and the numerical complexity of the model which involves iteration rather than a single step calculation (Parini and Riedel, 2000; Sanyal and Sarmiento, 2005).

One approach has been, rather than to carry out model runs using a large number of variations of the numerical model, to use sensitivity analysis on multiple runs of the same basic model to develop a simpler 'proxy' equation for the model (with up to say 10 variables) and then to apply the Monte Carlo method to that equation (e.g. Parini and Riedel (2000), Hoang *et al.*, (2005)). This approach has much to recommend it but is sufficiently time consuming and expensive (and hard to independently verify) that it is probably impractical and/or unaffordable for smaller developments and it would not be reasonable to make it mandatory even for Reserves estimation.

Probabilistic methods should preferably be applied separately to the different Resources or Reserves categories to improve understanding of the reliability of each of these. Care needs to be taken in this case to ensure that any implicit or explicit dependencies between parameters in each area are correctly managed in the probabilistic process. For example, if a certain range of porosity is assigned to a certain rock unit in one part of an area, it is improbable that it is very different in the same unit in another part of the area, and yet an unlinked Monte Carlo type simulation would allow such a situation to arise.

Risk Factors and Constraints Other Than Energy

Attention should be paid to possible technical constraints to development other than energy and its recoverability. There may be aspects of a geothermal resource which render certain sectors of the resource unusable and may mean that those sectors should not be included in the Resource or Reserve assessment. They include the following:

Fluid Chemistry

In naturally convective systems with surface manifestations, it may be possible to directly identify any serious or fatal constraints to development such as serious magmatic acidity or high gas content and adjust the Resource estimate accordingly. In systems without surface manifestations, fluid chemistry can only be predicted approximately in advance of drilling, by analogy and a knowledge of the geology.

In HFR or deep extensive sedimentary aquifer situations fluid chemistry is likewise important but the fluids are probably going to be more consistent than in naturally convective systems because lateral and in some cases vertical temperature gradients are smaller and there are no magmatic volatiles being added. In HFR or deep sedimentary aquifers the fluids are old enough to have reached full equilibrium with the rock, and are single phase rather than including shallow gas accumulations, so fluid chemistry will be a function only of rock type, surrounding geology and temperature. Provided consistency of rock type and temperature are confirmed, there is therefore no need for separate specific verification of fluid chemistry by offset drilling and flow testing. If however significantly higher temperatures are encountered it may be necessary to reconsider chemical issues to see if any additional scaling problems arise.

In HDR systems where fluid is artificially added, fluid chemistry can be expected to give fewer surprises though certain rock types such as carbonates could still give rise to problems.

Acidity in geothermal systems can cause major damage to well casing and surface pipelines to the point where the well is unsafe. It is much more likely to be a problem in natural convective systems than in EGS or most HSA systems. Fluid acidity has three principal forms, and the origin of the acidity affects its distribution. Therefore it is important to determine its origin, so as to know which zones should be omitted from Resources and Reserves. The three types are:

- *Magmatic* acidity is more likely to occur in the hottest and otherwise most attractive part of the resource. Acid-magmatic vapour can exist below a neutral pH reservoir or in localised parts of a system, hence magmatic acidity need not be a fatal constraint, but it may be necessary to delete significant portions of the system from the Resource estimate.

- *Surficial acid-sulphate* waters of secondary origin, formed by the oxidation of steam condensate, are the most common form of acidity in geothermal systems. The occurrence of secondary acid zones is more likely to lead to certain shallow zones (which are therefore relatively low temperature) being removed from the Resource estimate rather than whole areal sectors. In the less common case where they penetrate more deeply into the neutral system they may effectively sterilise part of the resource. This is more likely to be the situation in systems under elevated terrain such as in island arc systems in the Philippines and Indonesia
- Acidity due to *sulphur dissolution and hydrolysis* is comparatively rare. It is most common at shallow levels. This is the type of acidity that is most likely (though still not highly probable) in amagmatic situations. There is no example known where it has affected a large proportion of a resource.

The occurrence of acidity at depth in natural geothermal systems can be predicted from the geochemistry of the thermal features.

Scaling in the production wells, surface heat exchanges and reinjection wells is potentially a serious problem for any geothermal project. The most common forms of scaling in geothermal wells and in the formation are calcite ($CaCO_3$) and anhydrite ($CaSO_4$). Other forms of well scaling are known (e.g. stibnite) but are sufficiently uncommon that they have to be assessed on a case by case basis.

Calcite deposition is most common in more dilute alkaline-pH reservoirs, particularly those with high gas contents or relatively low temperatures (e.g. < 220°C). It can affect both magmatic and amagmatic projects.

Where anhydrite deposits in the wellbore, this is almost always as a result of mixing of neutral-pH, calcium-rich water with secondary low-Ca, SO_4-rich waters. Usually the latter are surficially derived acidic waters that have ingressed to reservoir depths along permeable structures.

Silica deposition poses a significant problem because of scaling in pipelines and in reinjection wells. The higher the temperature of a geothermal fluid, the greater the quantity of dissolved silica it contains, and so the more readily it deposits silica when cooled or separated. In flash-steam projects the standard low cost approach to controlling silica supersaturation has been to design the system to operate at a separator pressure at which saturation with respect to amorphous silica is not greatly exceeded. Similarly in combined cycle or pure binary projects fluids are kept close to silica saturation by limiting the amount of heat which is conductively extracted, and hence keeping the reinjection temperature above a certain limit. These limits have to be kept in mind when setting the Rejection Temperature for Resources and Reserves (Appendix A).

More recently success has been experienced in some projects with chemical inhibition of silica scaling, in particular by pH modification of the separated brines to delay silica polymerisation and this is likely to become more common as energy prices rise.

In some cases the presence of fluid which could cause calcite or anhydrite scaling may lead to removal of certain zones from a Resource estimate, but it is more likely to indirectly affect the whole of the Resource by affecting the project economics. That is even more the case with silica deposition, since it is unusual (but not unknown) for a project to deliberately avoid the hottest parts of a resource. The likelihood of silica scaling is in a different category to calcite or anhydrite scaling: it is directly linked to fluid temperature, and so is an inevitable but quantifiable constraint.

Gas Content. The non-condensable gas fraction of geothermal fluid in high temperature systems is usually mainly carbon dioxide, with about 5% hydrogen sulphide. A high gas content in geothermal steam is undesirable for four reasons: it is often linked to a high calcite scaling potential; it imposes an increased parasitic load on the plant, through the need to pump gas to maintain low pressures in the steam condensers; it can lead to corrosion of wells and plant for example through hydrogen embrittlement of steel and it can pose environmental problems for disposal.

Gas content is rarely a fatal constraint, and its effects are economically quantifiable, but it is not always accurately predictable. The gas content in steam from fumaroles can be measured, but this will not be the same as the gas content at depth. Nor can it simply be taken as a maximum or minimum, since there are two conflicting processes at work: an increase in gas due to condensation, and a decrease in gas along outflows. Only by an appreciation of the setting of the thermal features within the hydrology of the system and specific geochemical modelling can a reliable estimate be made. Gas content in steam may also vary with time in response to reservoir processes such as boiling. Total gas concentrations in steam at Ohaaki in New Zealand more than doubled during the first two years of production.

In both conductive and convective systems (but not HDR systems) there could be zones with shallow gas accumulations which should not be included in the Resource estimate, though that is more likely in natural magmatic systems. In most cases a high gas content is more likely to affect the economics and so the whole of the Resource estimate indirectly.

Apart from the physical effects, gas content is important in how it may affect economic benefits, such as carbon financing, that may be expected from the development of geothermal as a clean energy source. Prediction of gas emissions from future plants requires consideration not only of the gas content in the reservoir, but the nature of the power plant, since that can have a large effect on the quantity of gas emitted.

Accessibility

Although a prospect may have good resource characteristics, the commercial development of the field may be restricted by problems related to surface conditions such as the nature of the terrain and accessibility. If access is restricted, then this may also have an impact on the definition of the areal extent of the resource that can be economically accessed. For example, it may be relatively simple to develop an outflow from such a system but it may not be possible to drill into the main high temperature area without significant expense, either in preparation of wellpads or in drilling highly deviated wells. To some extent undrilled zones can contribute to the resource by lateral drainage, but the extent to which that should be included in a resource assessment over distances of more than a kilometre or two is questionable. In exceptional cases, though, such as Wairakei in New Zealand, lateral permeability is extremely high and fluid drainage over distances of more than 7 kilometres is apparent from data such as monitored well pressures, gravity changes and ground subsidence.

Environmental Impacts

It would not be usual practice to go into possible environmental impacts (real or perceived) or land use conflicts in detail in a Resource or Reserve estimate (though they would be addressed in a bankable feasibility study), but they may present reasons to exclude certain resource sectors from consideration and if so this should be explained. Any regulatory constraints must also be recognised, for example constraints impacting fluid production and reinjection.

Comments on Specific Methodologies

In this section some more specific suggestions are given as to preferred approaches to be adopted, some default parameters, and some pitfalls to be avoided, for each of the methods described in the previous section where it is considered they can be meaningfully applied for resource and reserves estimation.

Volumetric Methods

The principle of the stored heat method is to estimate the heat stored within the defined reservoir volume, above some base temperature based on the energy conversion technology assumed, which must be stated. The base temperature is typically less than 100°C (with the exception of a stand alone condensing steam turbine where the base temperature could in some cases be considered equal to the separator temperature, typically 150°C or more). There is also a separate cut-off temperature used to select the reservoir volume to be included, which in un-pumped reservoirs with flashing flow should be related to the minimum at which a well will self-discharge.

Williams (2007) has shown that much lower cut-off temperatures may be applicable where heat is swept from cooler field margins or the injection area towards the high temperature centre of the system. This is analogous to a counterflow heat exchanger where heat can be transferred from one medium to another leaving the source cooler than the output.

In pumped situations including HFR the cut-off temperature will be related to the rejection temperature plus any expected fluid cooling before it reaches the wellhead, though some economic criteria may also be applicable. Once again the selection of that temperature should be justified.

The stored heat includes both the heat stored in the rock and the heat stored in the reservoir fluid, though in almost all case the heat stored in the rock will strongly dominate even in high porosity naturally convective reservoirs. The reservoir volume is usually taken as the areal extent multiplied by the drilled depth plus some storage volume, commonly another 500 m in convective reservoirs, but a smaller figure should be used in conductive reservoirs because of the much slower rate of heat transfer.

The equation used to calculate the stored heat is:

$$Q = A x h \; x \; \{ \underbrace{[C_r \; x \; \rho_r \; x \; (1-\phi) x (T_i - T_f)]}_{\text{heat in rock}} + \underbrace{[\rho_{si} \; x \; \phi \; x \; (1-S_w) \; x \; (h_{si} - h_{wi})]}_{\text{heat in steam}} + \underbrace{[\rho_{wi} \; x \; \phi \; x \; S_w x \; (h_{wi} - h_{wf})]}_{\text{heat in water}} \}$$

where:

	Sw	= relative water saturation
	Q	= stored heat
	A	= areal extent of the reservoir
	h	= average reservoir thickness
	C_r	= specific heat of the rock at reservoir conditions
	T_i	= initial average reservoir temperature
	T_f	= rejection temperature
	ρ_r	= rock density
	ρ_{si}, ρ_{wi}	= steam and water density at reservoir temperature
	$h_{si,} h_{wi}$	= steam and water enthalpies at reservoir temperature
	h_{wf}	= water enthalpy at cut-off temperature
	ϕ	= porosity

Note that the reservoir temperature is the *average* through the volume considered (laterally and vertically), not the maximum. Using the maximum measured temperature as the maximum possible value for the average resource temperature in a probabilistic stored heat estimate is a common error which leads to excessively large estimates. In order to estimate a Resource or Reserve under the Code it is necessary to define a recovery factor to determine the amount of stored heat that can be extracted.

In order to estimate the possible size of a power development, it is necessary to apply some additional factors to the total recoverable heat estimate. These include:

- A conversion efficiency for converting the recovered heat to electricity, which takes into account the Base Temperature (see Appendix A).
- The economic life of the project. This is used to divide the energy content from the previous step by time to give an average output in MWth or MWe.
- A plant factor, which combines both plant availability and plant capacity. This allows for planned maintenance activities and/or unforeseen problems that cause a shutdown and whether the plant will be base load or load following. In most existing geothermal plants, this factor is between 90% and 95%, but for projects using novel technology or with demanding pumping requirements the factor for the scheme as a whole should probably be lower than that. For projects that employ a number of modules, the factor is likely to be at the high end of the range.

Some guidelines as to how to select these factors are given below.

The final estimate of electrical power potential (MWe) is calculated using the following equation:

$$E = \left[\frac{Q \cdot R_f \cdot \eta_c}{F \cdot L}\right]$$

where:

where:	E	= power plant capacity
	Q	= total stored heat
	R_f	= recovery factor (fraction of stored heat extracted)
	η_c	= conversion factor
	F	= power plant capacity factor
	L	= power plant life

Rather than manually estimating the stored heat, it can be determined from a numerical simulation model. One instance where this may be useful is for a project which has been under production for some time and account needs to be taken of energy already extracted when doing an estimate of the remaining Reserves or Resources.

There are various means by which a stored heat assessment can be refined, for example:

- Divide the reservoir into more, smaller blocks and assess each separately for temperature, density, void space, etc.
- Integrate the well temperature profiles rather than take an average temperature, and extrapolate to depth using some stated assumption for the temperature gradient such as boiling-point-for-depth, or a 3-D heat flow model, rather than simply isothermally. This can be also be done using a numerical simulation model.
- Assess steam zones separately by considering water, steam and rock as separate phases, and assess the recovery factor for steam in terms of the degree of water saturation at abandonment (Sanyal and Sarmiento, 2005). This is a more rigorous approach but unless a large proportion of the reservoir is occupied by steam zones it will make little difference to the outcome: Sanyal and Sarmiento (2005) presented an example showing only 3.4% difference in median reserves depending on whether two phase zones are separately assessed or not.

- Subdivide the temperature profiles into, say, 10°C steps and use the actual properties of water and steam (density and enthalpy) at each interval.
- Allow for the change in rock specific heat with temperature.

Given the large and rather arbitrary factors that are applied to recovery factors and lifetime of the project, and the considerable uncertainties in the reservoir volume, void space and temperature, it is questionable how much value such refinements add, apart from the first, or in the special case of extensive 'dry' steam zones.

Numerical Simulation Models

Numerical simulation modelling is the most complex form of reservoir modelling used in geothermal reservoir engineering. It is perhaps the only tool available that can be used to reliably forecast reservoir behaviour, particularly where two phase conditions are present. However, care needs to be taken as it becomes very easy to say that the results *must be correct* because they were produced by a model. In fact, as more experience is gained in modelling it becomes apparent that the major difficulty is having sufficient data to constrain the parameters required, rather than the internal methodology of the model.

Due to their unique ability of being able to forecast field behaviour, numerical models have become an important tool in helping financiers gain confidence that a particular geothermal field has the ability to support the proposed development. However, this information is needed at a relatively early stage in the development, when the parameters are not well constrained and uncertainties in the results are therefore relatively high.

The modelling process involves the following steps, which are discussed in more detail in the following sections:

- derivation of the conceptual geo-hydrological model including what is known of the geology and hydrology;
- construction of the numerical simulation model in line with the major features of the conceptual model;
- initial calibration of the simulation model by matching the main features of the conceptual model;
- further calibration of the model by matching available well test or production data;
- use of the model to forecast reservoir behaviour under various production scenarios; and
- continued up-dating of the numerical model to allow it to be used as a field management tool.

Conceptual Hydrological Model

In setting up a computer model, it is first necessary to have a good understanding or 'conceptual model' of the geothermal reservoir. The conceptual model is based on a multi-disciplinary assessment of all the data collected from the resource during both the exploration and development phases. The important aspects of the conceptual model that are useful for simulation modelling include:

- reservoir structure and litho stratigraphy, with associated parameters;
- subsurface distribution of temperature, pressure and water saturation;
- location and rate of fluid and heat recharge and discharge;
- subsurface distribution of fluid and gas chemistry.

In practice, the above information may or may not be available, or, if it is available, it may not be in a form that is useful for reservoir simulation. Litho-stratigraphy, for example, may indicate where different rock types occur within a geothermal reservoir but it does not necessarily define changes in hydraulic rock properties, such as permeability or porosity, that are important for reservoir modelling. Similarly, structure may define the location of significant faults within the reservoir but may not be able to define whether the faults are acting as conduits or barriers to the flow of fluid: both situations have been observed.

The subsurface distributions of water saturation cannot be directly measured. Methods are available to estimate water saturation in the vicinity of wells by analysing the discharge chemistry but the methodology and interpretation are as yet far from standardised and should be treated with caution.

The subsurface temperature and pressure distributions are the most important data available for reservoir modelling. These are based on interpretation of individual well data and provide information on the location of upflow and outflow zones and the thermodynamic state of the fluid in different areas of the reservoir. This interpretation is also helped by incorporating the well and field chemistry.

Although it is possible to locate the upflow and outflow zones, the actual flow through the system is also generally difficult to define. In some cases it is possible to estimate the heat and mass flow through a geothermal system but there is generally significant error in the estimates. However, it has been found from experience that the natural throughput even in convective systems is relatively small, particularly in comparison with the production rate that will be required for a geothermal development. Hence, the recharge rate is used in the natural state model as a fitting parameter.

The fluid and gas chemistry can provide useful information on both flow directions and the fluid and gas composition, which are important in defining the thermodynamic properties used in the model. However, where wells encounter multiple zones or the fluid flashes within the formation it may be difficult to derive the true reservoir chemical composition from discharge samples.

Setting up an appropriate conceptual model is not a simple matter but requires significant input from a number of different disciplines to decide if data are reliable and how the data can be used to arrive at a consensus model of the reservoir. Once a consensus model is available, then an initial state (or natural state) simulation model can be set up to mathematically describe the conceptual model.

Model Construction

Construction of the reservoir simulation model involves dividing the reservoir into a series of blocks and including appropriate boundary conditions. The aim is to set up the boundary conditions so that the model is capable of reproducing the heat and mass flows into and out of the system required to reproduce the known sub-surface temperature and pressure conditions.

Construction of the model therefore requires decisions to be made regarding:

- grid orientation;
- number of layers to be used;
- selection of grid blocks;
- definition of boundary conditions;
- initial estimation of rock properties;
- initial thermodynamic conditions.

Grid orientation and layering should be based primarily on the subsurface temperature distribution, major structural trends and the location of major production horizons. This may cause problems if the trends are not parallel or perpendicular although the temperature distribution is generally controlled by the major structural or stratigraphic trends. The ability to use irregular grid blocks is a property of the MULKOM/TOUGH family of codes (Pruess, 1990) and has proven to be a very useful concept.

The selection of grid blocks on any particular layer will depend on the density of available data and well locations. If two-phase conditions are present or expected to occur during the production phase, it may be useful to increase the number of layers in the model to allow a more accurate representation of the two-phase zone.

It is generally necessary to use additional grid blocks to define the boundary conditions in the model. The boundary conditions are generally set up to provide the heat and mass inflows and outflows to/from the model. These may be heat or mass and the boundaries may vary from closed no-flow boundaries to boundaries which maintain constant temperature and pressure conditions. Between these two extremes, various recharge boundaries may be defined, based either on total volume 'tank' models or pressure dependent models where the rate of recharge may change depending on the pressure differential between the boundary and the model.

It is also possible to specify point sinks or sources. These are effectively 'wells' and may be specified as constant rate (steam, water or total flow) or may be set up to provide a changing flow rate in response to pressure changes. The following equation is used in the MULKOM/TOUGH family of codes (Pruess, 1987) for this type of source:

$$q = \frac{k\rho}{\mu} \cdot PI \cdot (p_{block} - p_{wellbore})$$

where:

q = flow rate

k = permeability

ρ = fluid density

μ = fluid viscosity

It is also generally necessary to include a significantly larger volume than the known reservoir in the model to reduce the effects of the outer boundaries on the model results. This indicates that geothermal reservoirs cannot generally be treated as isolated systems and there could be significant interaction with the surrounding hydrologic system.

Estimation of initial rock properties and thermodynamic conditions are based as much as possible on the measured data used to define the conceptual model. The most important rock property in modelling is the permeability distribution and this may not be well known. Measurements on core samples often correlate poorly to bulk reservoir properties, and measurements on pre-stimulation cores will be completely different from post-stimulation in the case of EGS projects.

Initial or Natural State Modelling

Once the simulation model is set up, a trial-and-error technique is used in matching the major features of the conceptual model. The location and rate of recharge/discharge and the permeability distribution are the major variables used in matching the conceptual model.

The model is run in time until steady state conditions are reached and the results are then checked against the actual field conditions. It should be noted, however, that this process is not meant to reflect the evolution of the system in geological time. The main requirement is to have a stable model that fits the conceptual model and also acts as the starting point for matching available well test or production data. If the starting point is not stable, it is difficult to determine whether the changes are due to production or due to continuing evolution of the model.

If the model results and the conceptual model do not agree, it is then necessary to change some of the conditions in the model and repeat the process. The changes may include redefining the location and strength of inflows and/or outflows and changes to the permeability distribution.

History Matching

After the natural state model is considered to be in reasonable agreement with the measured data, the computer model is further validated by 'history matching', where the available discharge data from the field is matched using the computer model. History matching requires:

- preparation of the production/injection history for input to the model;
- possible redefinition of the grid block layout;
- matching the available pressure and/or enthalpy history that corresponds to the production/injection history.

For history matching to be successful it is necessary to have reasonably accurate records of the production/injection history. This is not always the case, particularly in two-phase geothermal fields where it is not possible to have continuous monitoring of well flow rates or enthalpies. It may therefore be necessary to estimate the production/injection history using indirect or inadequate data. In low or moderate temperature geothermal resources, where the fluid is produced by pumping, or in vapour dominated fields, it is much easier to obtain good discharge histories. In addition to production data, it is also very useful to have downhole pressure data from either active or observation wells. This data helps to constrain the hydraulic parameters in the model.

If two-phase conditions are present in the model, it is necessary to consider the effect of the interaction of the two phases on permeability. This is generally accounted for by using 'relative permeability' functions, which are defined for each phase as a function of water saturation. Although the relative permeability functions are not well defined for geothermal systems, the Grant functions (Grant, 1977) are probably the most widely accepted for geothermal reservoir modelling. They are expressed by the following equations:

$$S^* = \frac{(S_l - S_{lr})}{(1 - S_{lr} - S_{gr})}; \qquad k_{rl} = (S^*)^4 \quad and \quad k_{rg} = (1 - k_{rl})$$

where:

	S_l	= liquid (water) saturation
	S_{lr}	= residual liquid (water) saturation
	S_{gr}	= residual gas (steam) saturation
	k_{rl}	= liquid (water) relative permeability
	k_{rg}	= gas (steam) relative permeability

At the present time there is no reliable method available for deriving site specific relative permeability functions from measured field data. It has been found, however, that the model results may be sensitive to the functions used and also to the assumed residual water and steam saturations (Bodvarsson *et al.*, 1980). Hence, the relative permeability functions may themselves become an additional matching parameter for matching enthalpy transient data and, to a lesser extent, pressure data.

The matching of production data may require changes to the permeability and/or porosity distributions in the model which may change the initial state results. Therefore the model will need to be rechecked to ensure that any changes made during history matching do not significantly change the results of initial state modelling. If significant changes do occur, then the initial state modelling needs to be repeated until a more consistent model is obtained. This process may be repeated on a number of occasions before a model is obtained that is consistent with both the natural state conditions and the conditions caused by production, having due account for near-wellbore impedance and the much higher flow rates that are observed in geothermal reservoirs than in petroleum reservoirs. In other words it is better to match reservoir pressure trends than individual well outputs.

Forecasting Reservoir Behaviour

After the model has been validated by the initial state modelling and history matching, it can be used for predicting future performance for any required production/injection scenarios. Generally a number of scenarios are selected and the results compared to see how changes in the production/injection strategy affect the reservoir response.

In setting up the forecast runs, it is generally possible to define the production and injection wells using a number of methods; the actual method used will depend on the objectives. For example, if we want to maintain a constant steam supply from one or more separators, then it is necessary to build this option into the way the production wells are specified as the reservoir model generally calculates total mass flow and enthalpy as the production variables. Similarly, if the total injection flow rate is split between wells within a pressure limitation, it is necessary to have an option that allows the injection flow rate to change as the reservoir pressure changes and for additional wells to be brought online, as necessary.

It is a general rule, although often overlooked, that one can have reasonable confidence in the results from forecast runs for about the same period of time as used for history matching. Hence, in the development state or in early production, confidence in long term predictions is low. Confidence increases as more production occurs and the model is updated. There will probably be significant changes made to the model in the early years, particularly to the 'boundary conditions' which control long term behaviour.

Determining Resource Parameters

Some suggestions as to how to determine or select the key factors to apply in a stored heat estimate or a numerical reservoir simulation follow. A more wide ranging list of parameters and considerations is given in Appendix D.

Temperature

During the early exploration phase, no wells will be available to allow the resource temperatures to be measured directly. Indirect techniques in natural convective systems with surface manifestations, which provide samples of fluid that may have flowed sufficiently rapidly from depth that it has not chemically re-equilibrated, are based on the use of chemical geothermometers in which the temperature of the source can be inferred from the concentration and ratios of various chemical species present in the spring or fumarole discharges. There are both liquid (solute) geothermometers and gas geothermometers, and there are several in each category. Each has a range of applicability, and some are more consistently reliable than others (e.g. Williams *et al.,* 2008).

The temperature of the resource can be expected to vary with location; near the hot upflow the temperatures will be higher than near an outflow. There is thus a range of temperatures that can be produced, according to where the sample was taken, the type of geothermometer used, and the experimental error or uncertainty due to the sampling and analysis.

A Resource estimate should clearly distinguish between these different categories of temperature estimate. In some cases liquid temperatures at depth can reliably be estimated on the basis of inferring boiling-point-for-depth (BPD) conditions from the surface, in other cases water or gas geothermometry will give the best estimate. Each field must be assessed individually, on the basis of the hydrological model developed. Particular care must be given to the use of gas geothermometers. Some of these often yield higher temperatures than are subsequently encountered in drilling. There are three common reasons for this:

- the reactions are slow to re-equilibrate, and so they reflect temperatures at greater depth.

- there has been partial or complete re-equilibration to vapour in a steam zone;
- there are magmatic gases present.

If gas geothermometers provide the only data on which to base reservoir temperature estimates, as would be the case where there are no flowing neutral-chloride springs, then selection of which gas geothermometer to use must be constrained by a consideration of the hydrology.

In conductive systems, temperatures measured in shallow drillholes and physical measurements of rock conductivity on cores can be used to estimate temperature gradients which can be extrapolated to depth provided relevant constraints and uncertainties are recognised.

In the absence of extreme thermal gradients or rock units with significant vertical hydraulic permeability, thermal conduction is the dominant means of heat transfer in the Earth's crust. Conductive heat flow is the product of thermal gradient and thermal conductivity. In a steady-state thermal regime with relatively flat-lying strata, the First Law of Thermodynamics dictates that conductive heat flow remains constant with depth, or decreases with depth if there is significant heat generation within the crust. Heat flow can thus be extrapolated to estimate temperature at levels deeper than directly sampled. The accuracy of the extrapolated temperature profile depends on the accuracy of the surface heat flow value, the predicted thermal conductivity profile and internal heat generation.

A precise heat flow measurement from a shallow borehole requires a precision temperature log and accurate thermal conductivity measurements. Precise measurements of thermal gradient over intervals of several metres are correlated with thermal conductivity measurements over the same interval. Heat flow is the product of these two values.

Heat flow holes should have the following minimum characteristics: depth is several hundred metres to access rocks below the influence of surface seasonal temperature cycles, any known shallow aquifers, and to give a reasonable interval over which to measure thermal gradient; casing is set to keep the holes open for a minimum of four weeks, required to overcome the disruption to equilibrium temperature due to the drilling process; core is collected over significant intervals for accurate thermal conductivity measurements.

Temperature should be logged to a precision of about ±0.001°C and corrected for any thermal disturbance due to the drilling process. This precision allows thermal gradient estimates over intervals of several metres at a precision better than ±4%. (Thermal conductivity should be measured on core samples soon after extraction, in order to retain their in situ moisture and porosity levels). Careful field and laboratory practices can provide conductivity values accurate to better than ±3%. Heat flow measurements over individual intervals in the borehole can then be derived to accuracy better than ±7%. Five or more internally consistent, independent measurements within the same hole statistically improves the certainty of the heat flow value to better than ±3%.

An assumption of steady state conductive heat flow allows us to estimate the temperature profile down to any arbitrary depth. Assuming heat flow remains constant with depth, the thermal gradient through each rock unit varies inversely with thermal conductivity. The starting point for temperature prediction is, therefore, an accurate surface heat flow measurement and the construction of a stratigraphic column with thermal conductivity values for each unit. Uncertainty in the predicted temperature increases with depth below the heat flow measurement, uncertainty in thermal conductivity, uncertainty in internal heat generation, and the degree to which the assumption of pure vertical heat flow holds true.

Added complications include thermal conductivity anisotropy for strongly foliated units, which may change orientation with depth; the temperature dependence of thermal conductivity, which dictates an iterative correction is needed to accurately predict temperature at depth; decreasing heat flow with depth if significant heat is generated within the strata.

There can also be issues with 2-D or 3-D effects, where geology is not uniform, resulting in refraction of heat flow.

Enthalpy

At an early stage of field development, a discussion of enthalpy would probably be limited to whether the reservoir is likely to be vapour-dominated or liquid-dominated. There may be clues to this in the nature and chemistry of the surface thermal features and by analogy with similar developed geothermal systems.

Later on estimates of reservoir enthalpy are derived from direct sub-surface temperature measurements from wells and from flow test data. However, the discharge enthalpy from a well may be affected by flashing in the reservoir and heat transfer from the rock to the flowing fluid. Hence, the estimates of reservoir enthalpy should be constrained by including chemical geothermometry in the analysis and possibly by modelling of individual well discharges. This should help to eliminate the effects of near-well boiling which are of particular concern in hot zones of low permeability.

Similar comments apply to temperature measurements in wells: one needs to be sure that the measured temperatures represent the actual formation temperatures. If there are interzonal flows, it can be very difficult to determine the formation temperatures unless a number of surveys are available under both static and flowing conditions.

These effects are more of a problem in natural convective systems with high permeabilities, but they could still cause mis-interpretations in otherwise conductive systems if aquifers with different degrees of artesian pressure are encountered.

Resource Area and Thickness

The main basis on which the areal extent of the resource is defined during early exploration are the results from available geophysical surveys: resistivity and possibly aeromagnetics in the case of natural convective systems, temperature gradient drilling, seismics and probably gravity and possibly seismics in the case of HSA or EGS systems.

The size of the geophysical anomaly should not, however, be simply taken to correspond to the area of the field if there is high permeability. It should be constrained by the hydrological model, so as to exclude obvious outflows or other areas which on geological grounds do not constitute the economically recoverable Resource. If there is some geothermometric basis on which to estimate a temperature gradient within the reservoir, then an appropriate lower temperature limit at which to exclude areas will also need to be defined.

Areas of the play which appear to be inaccessible to drilling should be noted, but small areas should not necessarily be subtracted when estimating reservoir volumes, as fluid may still be drawn from these areas subsurface for a kilometre or two.

At a later stage the reservoir area can be more accurately estimated from the well data but it is likely that the geophysics will still need to be taken into account.

Resource thickness refers to the mean thickness of the reservoir which can be estimated, based on the results of drilling and analysis of downhole survey data. For an outflow, or where there is a permeable layer of limited vertical extent, this can often be easily defined. Otherwise, it can be taken that the upper surface corresponds to the depth slightly above that at which production casing may be typically set (which would normally include some contingency above the cut-off temperature, perhaps being at 240°C for a high temperature system) and the bottom to a maximum economic vertical drilling depth, plus some allowance for heat and fluid storage. If there are clear distinctions between vapour and liquid dominated zones, the thicknesses of each could be estimated separately.

Void Space

Void space in this context is an estimate of 'connected void spaces in the rock', expressed as a volume ratio. Thus it includes both matrix and fracture porosity as both contribute to the overall storage capacity of the reservoir. Although void space is important to the fluid storage capacity and the recovery factor, it is generally accepted that it has a relatively small impact on the overall heat storage in the reservoir (Watson and Maunder, 1982). The vast majority of the heat in a geothermal reservoir is contained in the rock rather than the fluid.

Water Saturation

Water saturation is defined as the *volumetric* fraction of water within the void space. The volumes of water and steam stored within the geothermal system are therefore defined by:

$$V_w = V_t \cdot \phi \cdot S_w \quad \text{and} \quad V_s = V_t \cdot \phi \cdot (1 - S_w)$$

where:
- V_w = volume of water
- V_s = volume of steam
- V_t = total reservoir volume
- S_w = water saturation
- ϕ = void space (pores and fractures)

If the geothermal system is liquid-dominated, as would be the case in all except some naturally convecting magmatic systems, then the water saturation will be close to one and the void space will be essentially filled with water.

In vapour dominated systems, such as The Geysers, Lardarello, Darajat or Kamojang, the water saturation is not zero; in fact, significant quantities of water are needed in the reservoir to explain the longevity of these systems.

The critical value of water saturation at which the pressure gradient within the reservoir changes from hydro-static (liquid dominated) to vapour-static in exploitation-induced steam zones, such as Wairakei in New Zealand, appears to be between 60 and 80% (e.g. Allis, 1982).

The degree of water saturation in two-phase zones does not make a large difference to stored heat estimates but it is very important for determining the long term performance of the reservoir in numerical simulation models.

It is not possible to directly measure the water saturation in a geothermal reservoir in the same way as temperature and pressure are measured. In an initial estimate it is therefore necessary to estimate it by analogy with similar systems. Estimates of the initial water saturations at various vapour dominated fields have been presented in the literature; for Darajat (Whittome and Salveson, 1990) and Kamojang (Grant, 1979, modified by *pers. comm.* 1996) these estimates range from 25% to 33%.

A numerical model of The Geysers constructed by Williamson (1992) indicated that it was necessary to include water saturations of up to 25% in the fractures and 83% in the matrix in order to match the measured pressure drawdown associated with the 30 year production history of the field. In this case, the water in the relatively impermeable matrix provides the fluid reserves for the system. As the pressure declines, the water boils to steam and flows to the wells through the fractures. The model of The Geysers was updated by Pham and Menzies (1993) and it was necessary to increase the initial water saturation in some areas of the model to match the updated production data.

Further discussion of typical values of water saturation in steam zones are included in Grant (1979) and Horne *et al.,* (1995) while methods of estimating saturation are given by Grant (1979), Arnorsson (1995), D'Amore and Truesdell (1995), Horne *et al.,* (1995) and Grant *et al.,* (1996). These methods are based on the analysis of chemical species under production conditions, but none have yet proven sufficiently reliable for routine use. Hoang *et al.,* (2005) commented that applying different methods to the Darajat reservoir resulted in values ranging from 20 to 90%.

Reservoir Mass

In addition to knowing the volumes of rock, water and steam in the reservoir, it is also necessary to know these quantities in terms of mass. The mass quantities are related to the volume quantities by the rock and fluid densities. For the rock this is not difficult as in most cases a constant value of rock density can be used, though note that the rock density relates to mineral density, rather than the bulk density of the rock which includes the void space. The mass of rock is then estimated from:

$$M_r = V_t \cdot \rho_r \cdot (1 - \phi)$$

where: M_r = mass of rock
V_t = total reservoir volume
ρ_r = rock particle density
ϕ = void space

In contrast, steam and water densities vary significantly with temperature and it is therefore necessary to have a reasonable estimate of reservoir temperature in order to define the densities; once this is known, the appropriate densities of steam and water are found from steam tables. The mass of water and steam in the reservoir are estimated from:

$$M_w = V_t \cdot \rho_w \cdot \phi \cdot S_w \text{ and } M_s = V_t \cdot \rho_s \cdot \phi \cdot (1 - S_w)$$

where: M_w = mass of water
M_s = mass of steam
ρ_w = density of water at reservoir temperature
ρ_s = density of steam at reservoir temperature

Although the above calculations are simple, they assume that the water saturation is known, but as mentioned in the previous section, this is not normally the case in two-phase reservoirs.

The only information available may be discharge enthalpies estimated from the testing of the wells. If the discharge enthalpies agree with the water enthalpy corresponding to the downhole temperature at the production zone, then the reservoir probably contains single phase water. However, if the well is producing two-phase fluid or steam then it is very difficult to relate the discharge enthalpy back to an in-situ water or steam saturation. This is due to the different mobilities of steam and water (relative permeabilities) and the possibility that the fluid is gaining heat from the reservoir rock as it flows towards the well.

It may be possible to estimate the enthalpy of the in-situ fluid, either by measuring the discharge enthalpy at very low flow rates or by extrapolating the trend of flowing enthalpy vs. wellhead pressure to low flow conditions. If this is possible, then the mass fractions of steam and water in the reservoir can be calculated, as follows:

$$x_s = \left[\frac{h_t - h_w}{h_s - h_w}\right] \text{ and } x_w = (1 - x_s) = \left[\frac{h_s - h_t}{h_s - h_w}\right]$$

where:
- x_s = steam mass fraction
- x_w = water mass fraction
- h_t = total fluid enthalpy
- h_s = steam enthalpy at reservoir conditions
- h_w = water enthalpy at reservoir conditions

The mass fractions can then be used to estimate the mass of steam and water in the reservoir. The relationship between water mass fraction and water saturation is as follows:

$$x_w = \left[\frac{\rho_w S_w}{S_w(\rho_w - \rho_s) + \rho_s}\right]$$

Even at relatively low values of water saturation, the mass fraction is still very high due to the significant difference between steam and water densities. The energy per unit *volume* of fluid (but not per mass) is therefore greatest in liquid-dominated resource, and increasingly so at higher temperatures.

Reservoir Permeability

Various methods are available for estimating reservoir permeability. In general, the estimates are based on analysis of pressure transient tests where the pressure change caused by production or injection is measured and analysed. These tests may be either single well tests or interference or tracer tests which involve both active and observation wells. It is important to distinguish between parameters that apply to the immediate vicinity of the well where high flow rates are concentrated from small aperture fractures with consequent high near wellbore velocities, such as skin factor, and parameters that can be applied to the wider reservoir. This may be particularly relevant for EGS projects, since stimulation may be more effective close to the wellbore.

The measured pressure gradient in the reservoir may also be used to estimate the vertical permeability in the upflow zone if estimates of the natural flow through the system and the flow area are available.

A convenient summary of both permeabilities and porosities as well as other properties measured in many natural convective high and low temperature systems worldwide is given by Bjornsson and Bodvarsson (1990). They found only a weak correlation between porosity and permeability, and a clear distinction between matrix dominated and fracture dominated reservoirs.

Recovery Factor

The recovery factor, which describes the fraction of the stored heat which can be economically extracted is now particularly important, as in the Second Edition of the Code a major change has been made which defines Resources and Reserves in terms of economically recoverable energy rather than energy in place. The Code also refers to default use of the Lexicon to define recovery factors for this purpose,

While conceptually simple, recovery factors are very difficult to predict and are hard to define. Even in reservoirs with up to 50 years of operating experience there is no complete consensus in the scientific literature as to how the recovery factor should be defined or determined (e.g. Grant, 2000).

For the present purposes recovery factor is defined to be the fraction of heat in place that can be carried by fluid to the production wellhead. It therefore includes any energy losses as fluid travels up wells, though there is a case for identifying that separately in calculations in the situation where there are large conductive losses, as it will be dependent on flow rate and well configuration which are not dependent only on reservoir parameters. It is not to be confused with the efficiency of conversion of heat to electricity. Some previous work has combined those factors but the Second Edition of the Code requires that they be treated separately.

It is also important to relate the recovery factor to the Base Temperature, in that if the Base Temperature is set unrealistically low, the recovery factor should logically be reduced. In early USGS estimates for example (Muffler, 1979), the Base Temperature was set at the ambient surface temperature, which means that there was unrecoverable energy between the ambient surface temperature and the practical operating rejection temperature for a power plant. In this case the actual recovery factor will be lower than where the Base Temperature is set to a more realistic level, for example the plant rejection temperature. Note however that this comment does not apply to the more recent USGS inventory, where a Base Temperature of 90°C for most of the USA and 75°C for Alaska appears to have been used, though this has not explicitly been stated (Williams *et al.*, 2008).

The Geothermal Lexicon is not totally prescriptive about the recovery factor to be used, but rather describes the range of factors that have been used in different settings in the past, and allows an appropriate factor to be selected for any individual resource estimate, with appropriate justification. Where there is insufficient information to justify a site-specific factor, some default values are given for various geological environments.

Some of the parameters that impact recovery factor are illustrated by Sanyal and Butler (2005) and in Figure 6 taken from that paper. They include reservoir geometry, well geometry and flow rates.

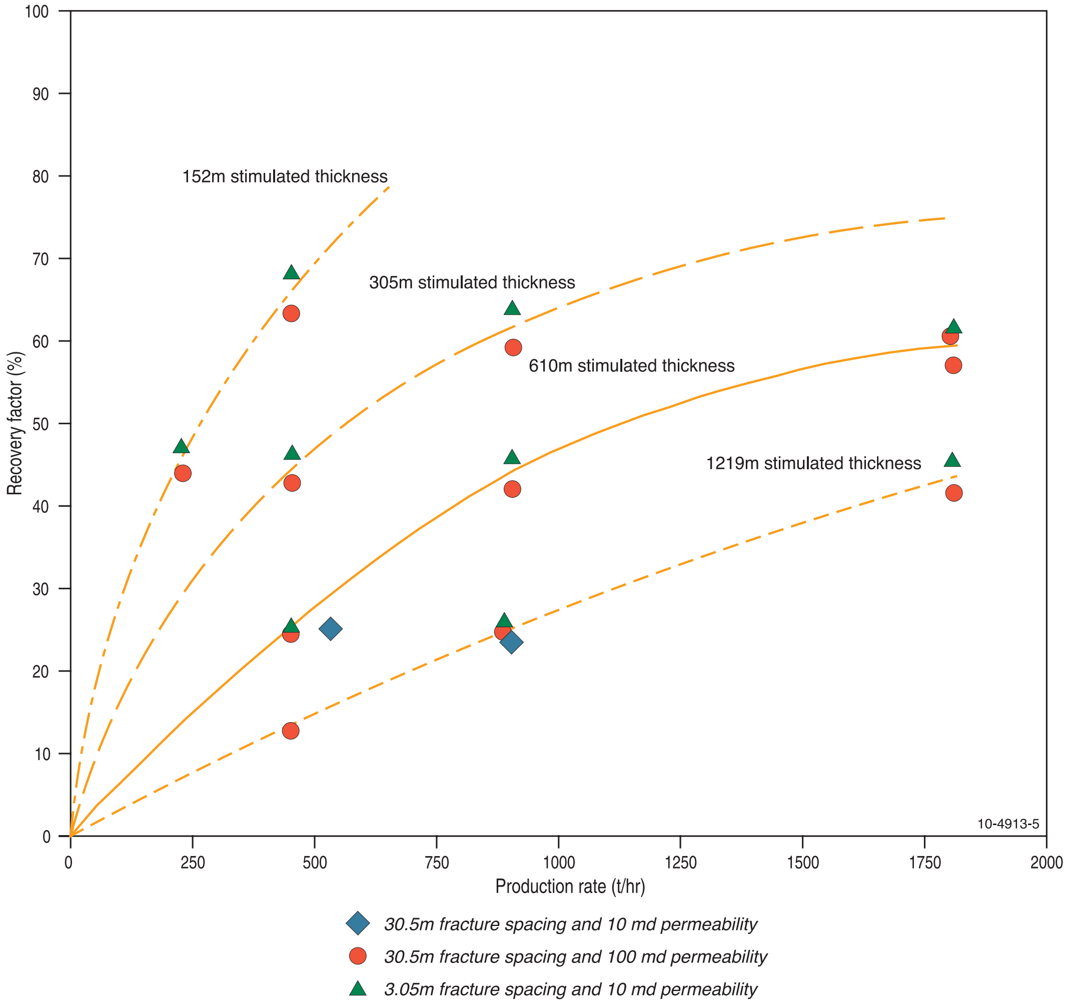

Figure 6: From Sanyal and Butler (2005).

Previous Work

In early stored heat estimates on natural convective systems the recovery factor was often taken to be between 25% and 50%. Early work by the USGS (Muffler 1979) used 25% for liquid dominated reservoirs without injection or recharge based on an analysis by Nathenson (1975), who also commented that recovery factors for vapour dominated systems should be much lower. These factors are sometimes still used in the USA.

Miyazaki *et al.,* (1990) assumed an average for Japan of 25%.

GeothermEx (2004) used 5 to 20% for naturally convective geothermal resources in the Western USA.

Sanyal *et al.,* (2004) carried out an analysis of how the earlier analysis by the USGS (Muffler, 1979; see also Reed, 1982) had stood the test of time when compared with actual reservoir performance, and with more recent work by GeothermEx (2004). They concluded that the resource estimates by Muffler (1979) tended to be about three times higher than the more recent estimates, and that the most significant factor in that difference was the recovery factor. A statistical comparison of the earlier USGS (Muffler 1979) estimates and the later ones (GeothermEx 2004) for the same fields suggested that an appropriate average recovery factor should be 11%, with a range of 3 to 17%. The USGS (Williams *et al.,* 2008) commented that:

"In general this apparent discrepancy in Rg reflects the contrast in thermal energy recovery from complex, fracture-dominated reservoirs compared to the uniform, high-porosity reservoirs considered in the early models. The original values for Rg were derived from models of the effects cooling in a geothermal reservoir due to reinjection or natural inflow of water colder than pre-existing reservoir temperatures (for example, Nathenson, 1975; Bodvarsson and Tsang, 1982; Garg and Pritchett, 1990; Sanyal and Butler, 2005). This is consistent with the optimal extraction of thermal energy from a reservoir, as in general it is possible to produce many times the original volume of fluid from the reservoir in order to recover the thermal energy from the reservoir rock. The challenge is to extend these results to evaluate the thermal effects of injection and production in reservoirs ranging from those containing a few isolated fracture zones to those that are so pervasively fractured as to approach the idealized behavior of uniformly porous reservoirs."

Most recently the USGS determined that for fractured reservoirs in the USA, the average is close to 10%, with a range of approximately 5 to 20% (Williams *et al.,* 2008). On that basis for the new USA national geothermal resource inventory they have adopted a range of 8 to 20% for fracture-dominated reservoirs, with a uniform probability over the entire range. For sediment-hosted reservoirs this range is increased from 10 to 25 %.

A possible alternative is to make the recovery factor dependent on the porosity: a recovery of 2.5 times the porosity to a maximum of 50% has been used empirically in some estimates, which appears to have a reasonable correlation with actual performance in reservoirs of high porosity and permeability based on experience in the Philippines (Sarmiento and Bjornsson, 2007). This may however not be applicable in reservoirs of different geology. It is also complicated by the fact that porosity measurements on cores in volcanic-hosted reservoirs often apparently underestimate the actual effective porosity which is required in reservoir simulation models and based on tracer storage.

Parini and Riedel (2000) took this further by using combined dual porosity numerical simulation and probabilistic methods to plot fluid recovery factor as a variable dependent on seven factors including temperature, porosity and permeability. Note that their results are expressed as *% fluid* recovery rather than energy recovery, so the numerical values are several times higher than if they had used *energy* recovery, but the same principles will apply.

The higher values above of energy recoveries over 25% are perhaps applicable in the type of natural geothermal reservoirs found in locations such as New Zealand, made up of pumice breccias whose porosity often exceeds 30%, and possibly in HSA resources with very clean sandstones, but it is questionable whether that should be applied in the same fashion in the very different geological environment of EGS systems which are virtually wholly fracture dominated, or in the fracture-dominated parts of naturally convective systems such as basement meta-sediments and crystalline intrusives.

Sanyal and Butler (2005) carried out a series of reservoir simulations to test sensitivities to factors such as well and fracture spacing for an EGS. They concluded that heat recoveries as high as 40% -50% would be possible with a suitably stable generation profile over time: greater heat recoveries were possible if greater permeability was created, but at the cost of rapidly diminishing generation with time. The risk of reinjection short-circuiting through a few large fractures under these circumstances suggests that the higher values are unlikely to be practically sustainable.

Recent work by Williams (2004, 2007) as part of a thorough review addressing specifically theory and experience in fractured reservoirs suggests significantly lower values. He reported an average value of about 10% for the three reservoirs in the USA which he considered had a long enough and large enough production history for the recovery factor to be assessed: The Geysers, Dixie Valley and Coso (Williams 2004). Later work (Williams 2007) used a more theoretical approach to suggest a range of 5 to 20%, intended to apply to both natural fracture dominated resources and EGS systems.

The difference between the result of Sanyal and Butler (2005) and that of Williams (2007) is that the latter drew on the concept of Bodvarsson and Tsang (1982) to predict non-uniform energy sweep over time intervals of the order of typical proposed geothermal energy projects. In that model significant amounts of energy are "left behind" in this time frame.

An interesting corollary of this approach but one that is not stated by Williams (2007) is that the cut-off temperature for stored heat estimates should ideally not be a fixed value, but rather should be lower in the injection sector and progressively higher towards the production wells.

Williams (2007) then used the results of tracer tests in productive fractured geothermal reservoirs to derive flow capacity/storage capacity curves to calibrate a fractal model whereby an estimate is made of the proportion of flow in larger and smaller fractures, following the work of Watanabe and Takahashi (1995), as shown in Figure 7.

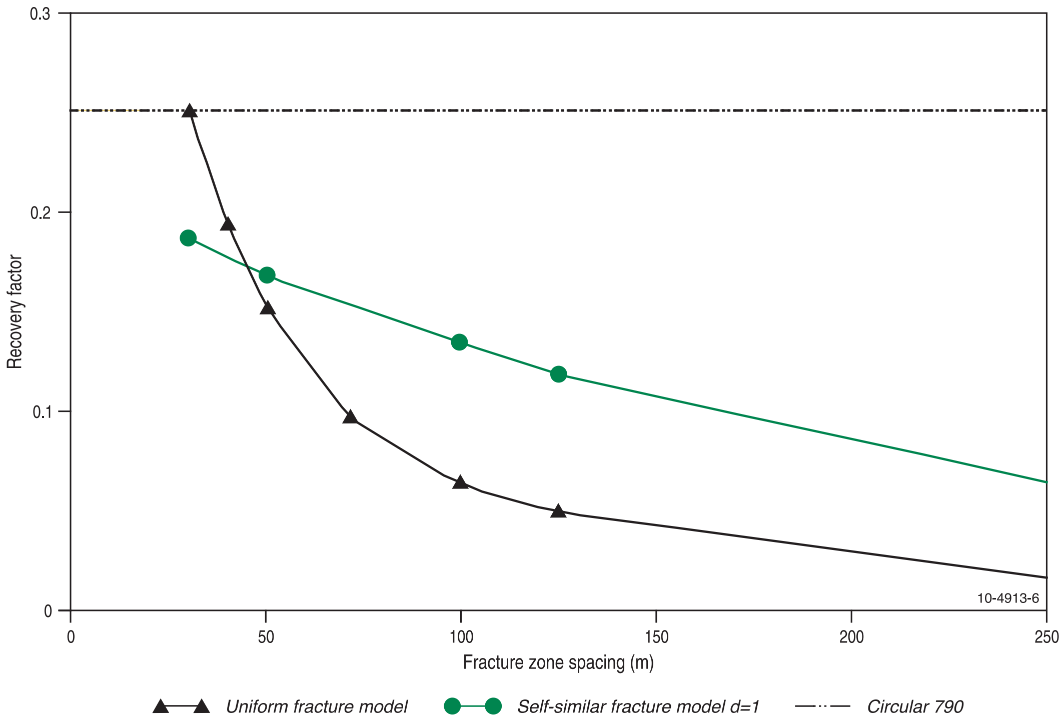

Figure 7: Variations in recovery factor with fracture spacing for example models incorporating planar fractures with uniform flow properties (black) and a fractal distribution of flow properties among the producing fractures (green). From Williams (2007).

Default Recovery Factors

Where there is an insufficient basis to propose and justify a site-specific recovery factor, the Base Temperature shall be set to a realistic plant rejection temperature for the climatic setting and the following Recovery Factors shall be used as defaults:

- In EGS and other fracture-dominated reservoirs, if there is sufficient information on fracture spacing, use the values implied by the uniform flow model in Figure 7 above. This will usually only be possible where there has been very close characterisation of the fracture density.
- In fracture dominated reservoirs (including EGS) where there is insufficient information to accurately characterise the fracture spacing, adopt the mean USGS value of 14%, or 8 to 20% with a uniform probability over the entire range when used in probabilistic estimates. However, it is important in the EGS case to restrict this recovery to the zones that have been stimulated, or, prior to stimulation, where there is a justifiable expectation that stimulation is possible. Energy recovery from un-stimulated impermeable granite will be essentially zero. If there is actual data on the probability distribution of permeability (or an appropriate proxy parameter for permeability) from offset wells, then a non-uniform distribution can be used, with higher recovery factors implied by higher permeability.
- In sedimentary reservoirs or porous volcanic-hosted reservoirs, of 'moderate' porosity (less than 7% on average), adopt the mean USGS value of 17.5%, or 10 to 25% with a uniform probability over the entire range when used in probabilistic estimates. If there is actual data on the probability distribution of permeability (or an appropriate proxy parameter for permeability), then a non-uniform distribution can be used, with higher recovery factors implied by higher permeability.
- In the case of sedimentary or porous volcanic-hosted reservoir of exceptionally high average porosity (over 7%), adopt the empirical criterion of recovery factor = 2.5 times the porosity to a maximum of 50%.

Conversion efficiency

Some confusion can arise because different studies have referred to the efficiency of conversion of all energy removed from the resource without consideration of the specifics of the technology, whereas others have more specifically traced the energy and mass flows through a defined process. The latter is to be preferred and should be mandatory for Reserves estimation, but the former approach is still to be found in the literature and could be applicable for less well defined Resources. A related issue is how the energy contained in used fluid is to be treated – is it to be added to the energy extracted if the waste fluid is not reinjected?

These issues can be illustrated with respect to the Wairakei geothermal plant in New Zealand, which is one of the few large geothermal projects in the world where a substantial proportion of the 'waste' fluid is not injected and where the mass and energy flows are well defined and publicly available. An illustrative analysis of Wairakei is provided in Appendix B, showing that, depending on definitions, the 'efficiency' ranges from 10 to 67 %.

In most cases estimates based on a defined conversion efficiency are based on the first law of thermodynamics: that is to say a simple difference in energy. An alternative approach is to take the second law into account and define an efficiency based on 'exergy'. The latter has been adopted in the new USGS national geothermal resource inventory (Williams *et al.,* 2008). While this is a good approach from a theoretical perspective, it is not as readily understandable by a non-technical audience and will give factors which are significantly numerically larger than an 'efficiency' based on energy only, which could make it difficult to compare different projects, so it is strongly recommended this approach should not be adopted.

Where a single factor has been applied to the assumed energy conversion efficiency without explicitly defining the process, in the past this has often been taken to be ~10%. With changes in technology, consideration should be given to varying the figure in situations such as the following:

- Very high or low temperature resources: one approach has been to make the conversion efficiency dependent on the reservoir temperature: SKM (unpublished data) have previously used the empirical correlation: (0.0484 x T°C -0.5096)/100 for high temperature natural geothermal systems where either large condensing turbines or combined cycle plant are to be used. Other workers have produced similar correlations for different plant types and temperature ranges. Some examples are shown in Figures 8 and 9, but one needs to be careful to understand the assumptions on which such plots are based.
- In projects where the resource temperature is predicted to decline significantly with time, it would be more correct to integrate a variable efficiency over time to allow for that, but this has not often been done.
- Resources with a high gas content where there will be high parasitic loads and hence lower efficiencies.
- Dry steam resources, where the conversion efficiency could be much higher, but the recovery factor is likely to be much lower.
- If the plant is more or less efficient than a standard plant. That could either be because of its mechanical design, or because of the ambient conditions. An example of the latter is the Mutnovsky plant in Kamchatka, Russia, which achieves a very high efficiency for a single flash condensing turbine because the average annual temperature is about 4°C (Povarov *et al.,* 2002). Similarly the oft-cited example of generation from 75°C fluid at Chena Hot Springs, Alaska is interesting, but as it relies upon use of 4°C cooling water it is not relevant in most other settings. Even in more 'conventional' settings, ambient temperature is important: for a typical air cooled binary plant operating on fluid at around 160°C, a 5°C difference in ambient temperature will change the plant efficiency by almost 1% (Figure 9).

Another approach which has some merit would be to make the conversion efficiency dependent on the power price as well as the temperature, based on the assumption that projects would use the most efficient technology they could afford.

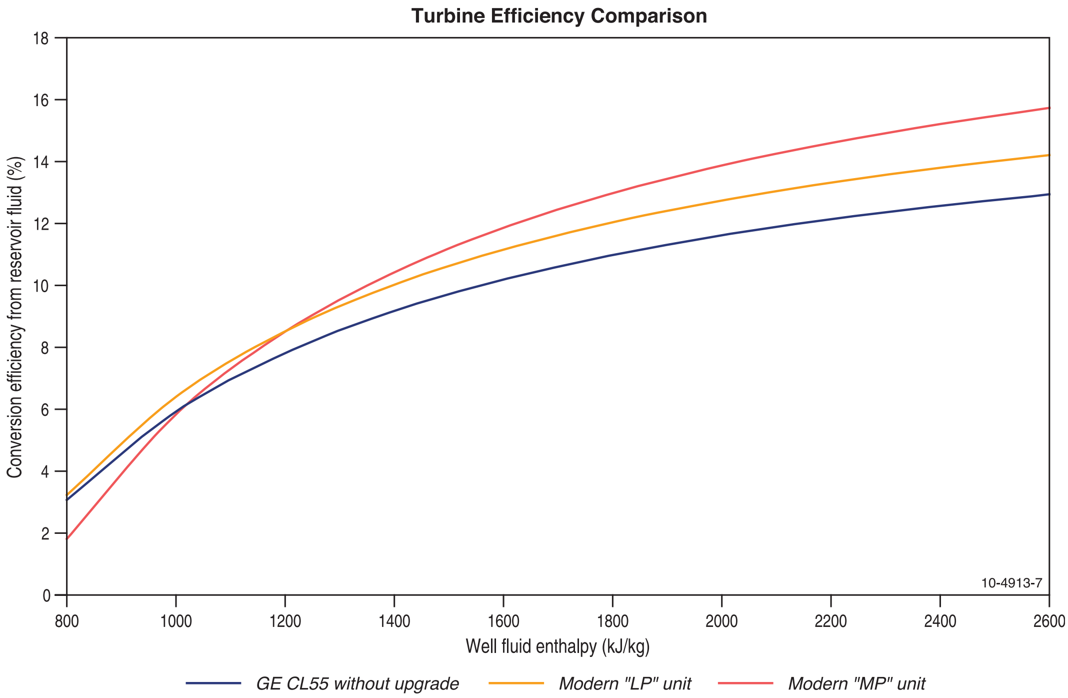

Figure 8: Typical efficiency for modern single flash condensing steam turbines and older marine surplus turbines such as have been used in some geothermal applications. Higher efficiencies are achievable for the latter with some modifications. Note that the efficiency in this case is based on the energy content of the whole of the fluid abstracted from the wells, including the separated water which is not made use of.

For the purpose of Reserves definition, it is suggested that where possible a more specific approach is adopted, using a reservoir enthalpy value, along with separation pressure, steam consumption rate, any binary, double flash etc. to calculate an energy conversion that suits the actual reservoir and proposed project.

It is important to distinguish between net and gross efficiencies and to define exactly what is meant in each case, since a variety of approaches and definitions have been used in recent estimates. To avoid confusion the following definitions are suggested:

'Gross' output refers to power production within the power plant limits ignoring in-house use and losses such as for cooling fans. It may be useful in a Resource estimate to mention the gross power output when describing the proposed process, but this figure should not be used to quantify Resource estimates.

'Net' output if used in an unqualified way refers to output at the power *plant* limits, subtracting in-house use but not production nor reinjection pumping nor transmission losses. The difference from gross to net for a typical ORC binary plant would be in the range of 10-20%, or less for a conventional steam turbine.

'Net to Grid' or 'Net to export' output refers to power delivered at the project power *scheme* limits, having subtracted production and reinjection power requirements and losses in the switchyard (which can be expected to be small), but not external transmission losses to the end-user. This is the best figure to use in a Resource or Reserve estimate. However, it is appreciated that it may be difficult to quantify pumping requirements at an early stage as with Inferred Resources, and the value will range widely: from zero in the case of a steam turbine with gravity reinjection to as high as 30% (additional to in-house losses) in some HSA or EGS projects. However, they must be estimated and included in the estimate of 'Net to Grid'.

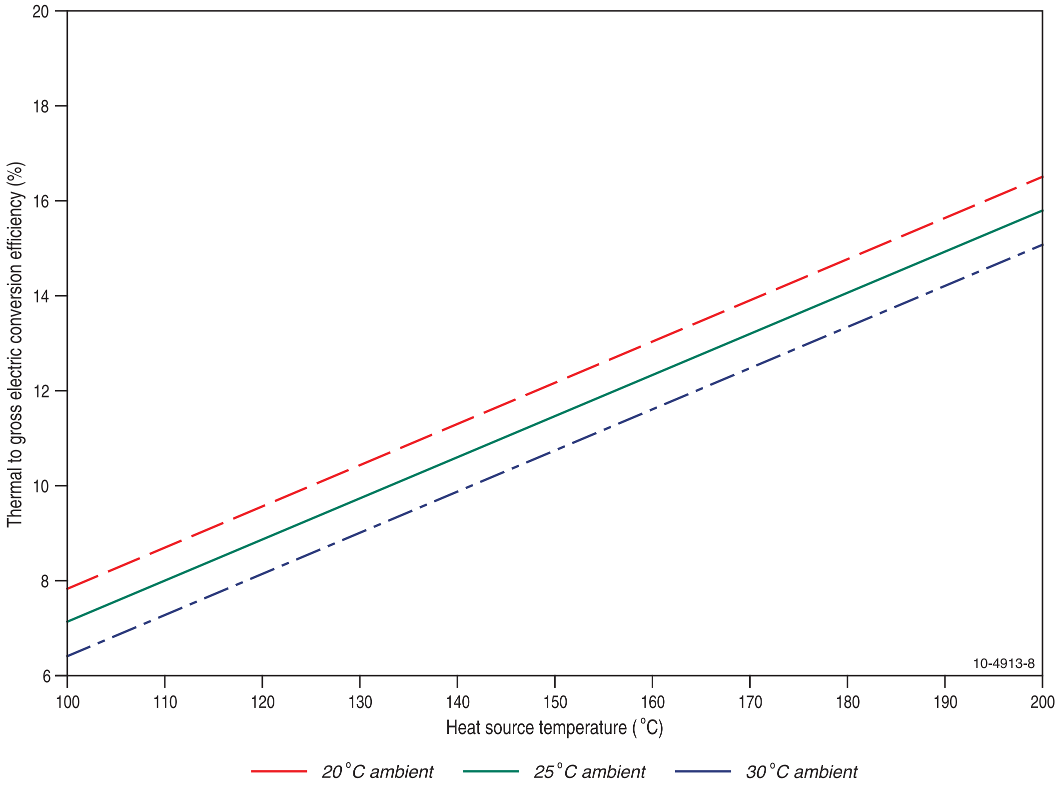

Figure 9; Typical efficiency for ORC binary plant, at a range of ambient temperatures and assuming single phase liquid input Note that the efficiency in this case is gross electricity output

Project Lifetime

It is common to use 20 to 30 years as a project lifetime in stored heat estimates and financial modelling, but for projects that have a quick pay-back period it may be worth considering a shorter period.

Grant (1996) presented a discussion of economic optimisation of plant size and hence depletion rate versus resource capacity, taking uncertainties into account. Such an analysis will usually favour maximising early extraction, but tend to ignore the physical risks of over-producing the reservoir, such as cold water incursion.

Non-economic considerations may also come into play (Clotworthy *et al.,* 2010). In some situations such as New Zealand longer periods of extraction can be mandated on sustainability grounds. For example resource estimates by Lawless (2004) for New Zealand were based on a 50 year project life for that reason.

Sanyal (2005) have argued that projects should be designed around a 'sustainable' capacity, with consequent longer project lives.

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Appendix A Definition of Temperatures Through a Production/ Reinjection Cycle

Figure A.1 shows a well production/reinjection doublet and power plant along with a number of points at which temperatures can be defined.

T_1 is the maximum temperature measured within the defined resource volume (assuming temperatures in the production well are pro-grade to the bottom). It will be higher than the average temperature within the defined resource volume, T_2, but could be less than the maximum temperature extrapolated to exist at greater depth within the defined resource volume than currently drilled (T_4). T_3 is the actual fluid feed temperature in the well, which could be the same as T_1 but will often be lower, especially if there are multiple feeds at different temperatures, in which case a mass-weighted average could be used. T_5 is the minimum temperature which is to be included in the defined resource volume for estimation – the cut-off temperature as defined above. It will be less than T_1, T_2 or T_3. It will often be lower than the temperature at the production well casing shoe, $T_{6,}$ as there should have been a degree of conservatism in selecting the casing depth. Further discussion is given by Sarmiento and Steingrimsson (2007).

T_7 is the temperature of the fluid once it reaches the wellhead. The difference between T_3 and T_7 will be dependent on the nature of the production: in the case of wells self-discharging two-phase fluid at high velocity there will be little opportunity for loss of heat conductively but there will be a loss of energy to gravity, friction and velocity which will be reflected in changes in both enthalpy and temperature, and temperature will drop significantly in the presence of any flashing. In the case of a pumped or artesian single phase well at low flow rate there could be significant loss to conduction. High-powered downhole pumps can also add some temperature.

Generally there will be little difference between the temperature at the wellhead, T_7, and the temperature where the fluid enters the power plant, T_8. However if there are multiple stages in the power plant, such as a steam turbine and binary ORC, the temperatures (and efficiencies) of each stage will need to be individually considered.

The rejection temperature from the power plant, T_9, may be significantly different from the brine reinjection temperature, T_{10}, especially in the case of a condensing steam turbine with a high separation pressure. The condensate injection temperature will be close to T_9, but condensate and brine may be combined for reinjection making T_{11} higher than T_9. Both will be higher than the ambient temperature, T_{12}.

Reinjected fluid may be hotter or colder than the original reservoir temperature at the site of reinjection, T_{13}. The fluid will then be progressively re-heated on its passage back to the production well. Williams (2007) made a convincing case for the cut-off temperature to be set to T_{14}, the average temperature between the reinjection and production well, since the reinjected fluid will be mining heat at well below T_3 and below T_5 as it travels back to the production well. In this case, selection of T_5 has to consider lateral as well as vertical temperature gradients, which is why two possible alternative resource volumes are shown in Figure A.1, depending on what assumptions are made.

Under various different scenarios, variations of the temperatures in Figure A.1 could be used in a stored heat estimate. It is suggested that this figure be reproduced within the documentation of a stored heat estimate and use made of it to explicitly define what assumptions and criteria are being used to define the cut-off and base temperatures in particular.

A further element not covered in Figure A.1 is the time dimension. In the case of HDR or HFR projects in particular there will be significant reservoir cooling over the lifetime of the project, and well deliverability will be less dependent on temperature because pumping somewhere in the fluid circuit can be assumed.

In that case the final reservoir temperature could perhaps be used as the cut-off temperature. Such an approach is less applicable in the case of a natural convecting geothermal system as there is more potential for hot recharge and phase changes, though reservoir cooling would be an implicit part of numerical simulation modelling in that case.

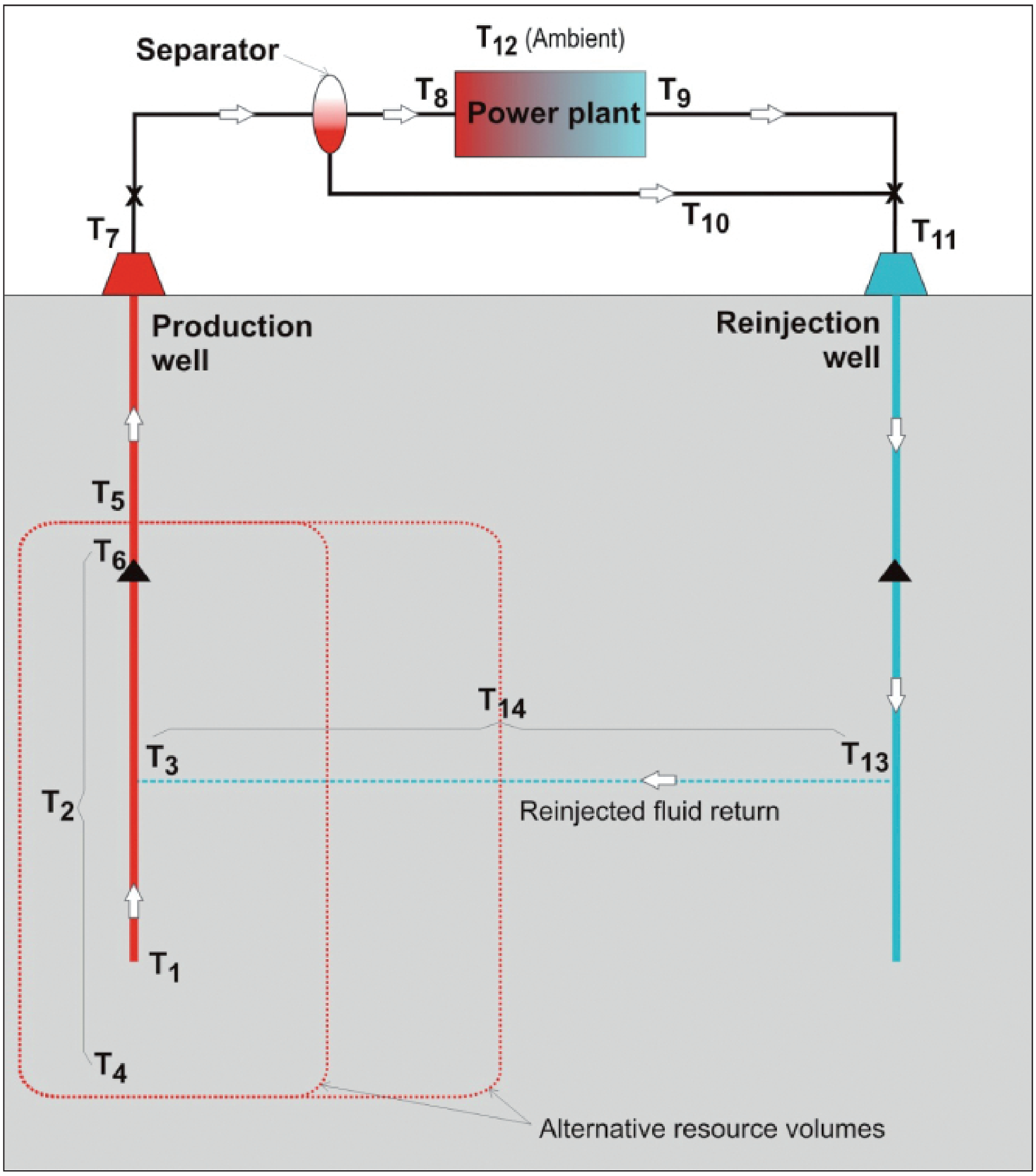

Figure A.1: (Figure 2 reproduced) Possible points for temperature definition within a production - reinjection well doublet and power scheme.

Appendix B An Example of Conversion Efficiencies

Any geothermal Reserves estimate for electricity generation must include some assumptions as to the thermodynamic efficiency of conversion of heat to electricity. Where a process and power plant technology has already been defined, or where the process is comparatively simple as in the case of a pumped single phase scheme utilising a binary plant with 100% reinjection, this can be done explicitly and accurately. But for more complex schemes or where the power cycle has not yet been defined there is a potential for alternative approaches which can lead to confusion if assumptions and definitions are not spelled out.

An example based on Wairakei in New Zealand is used to illustrate some of the possible alternative approaches and pitfalls. The information here is largely taken from White (2000). It is acknowledged that as a result of more recent developments the current and future operation of the Wairakei plant will differ in some respects from the details in White's report, nevertheless it provides a good 'snapshot' with which to illustrate the principles.

The analysis covers only the Wairakei plant itself, not the separate Poihipi or Tauhara energy schemes which tap the same Wairakei-Tauhara resource.

The facility was commissioned in 1958 and since has been modified both in response to changing reservoir conditions and to increase efficiency.

The Wairakei facility is currently a two pressure system utilizing both Intermediate Pressure (IP) geothermal steam and water as well as recycled lower pressure (ILP) geothermal water. The low pressure water is flashed and the resulting steam is used to produce more energy. After separation the separated geothermal water is either reinjected or discharged through a drainage system to the Waikato River. Some steam is discharged into the atmosphere via silencers when the residual fluid is discharged to the drains.

Within the power plant steam is condensed by direct contact with river water and the resulting mixture is then discharged to the river. Non-condensable gases are discharged to the atmosphere along with a small quantity of steam.

The net electrical production from the plant for the period described was 164 MWe.

Table B.1 shows the results for mass flow in the scheme under full operation:

Item	Mass (t/h)
Withdrawn from Reservoir	5331
Reinjected into Reservoir	1868
Discharged via Drains	1949
Discharged from Station	1460
Discharged to Air	188

The measured mass flows show a discrepancy of 134 t/h. This is a 2.5% error attributed to accuracies in measuring equipment which is ignored for the present purpose.

At the time of this evaluation, 1694MWth of energy was withdrawn. The temperature of the river at the point of discharge was 20°C and that is used as the base temperature for all energy calculations. Any energy losses between the wellhead and separator are assumed to be minimal. All energy lost that was not in the form of electricity or discharge to the atmosphere is considered to be lost to the river. Discrepancies in values are carried over from mass and pressure calculations and therefore are limited to the accuracy of the instruments. Energy used for cooling water and reinjection pumping and other in-house uses is assumed to have been subtracted from the net output. Table B.2 gives the energy flows:

Item		Energy (rel. to 20°C) (MW)
1	Withdrawn from Reservoir	1694
2	Reinjected into Reservoir	245
3	Discharged via Drains	84
4	Discharged from Station	916
5	Discharged to Air	206
6	Net Electricity produced	164

So how should the efficiency of the scheme be calculated? There are a number of possible approaches depending on whether one considers only the efficiency of the power plant as opposed to the power scheme as a whole, and whether there is 'credit' given for energy returned to the reservoir through reinjection. The range of possible outcomes is illustrated in Table B.3:

Basis	'Efficiency', %
6/(1-2-3-4-5)	67
6/(1-3-4-5)	34
6/(1-2)	11
6/1	10

The range of results demonstrates that the Wairakei *plant* is has quite high efficient even compared to more modern plants (because of the multiple flash system and the use of once-through direct contact cooling using river water), but the Wairakei *scheme* as whole has a low thermodynamic efficiency if energy lost through lack of reinjection is to be taken into account.

For the purpose of Resource and Reserve estimation, the most appropriate approach will usually be the third: that is to say the net electricity output divided by the net energy withdrawn from the Resource. Other approaches could be used but would need to be justified.

Appendix C Glossary and Abbreviations

Hydrothermal systems, features and physical processes

Boiling point for depth:	Pressure and temperature gradient in an unconfined fluid column where at every point the confining pressure is just sufficient to suppress boiling. Thus any pressure reduction at any point can induce boiling.
Boiling zone:	Zone of two-phase (*i.e.* boiling) fluid, generally within a hydrothermal upflow.
Conductive heat flow:	Heat transmitted through a (static) rock or liquid. A *conductive temperature profile* through a homogeneous medium is usually linear.
Convective heat flow:	Heat transmitted by movement of a fluid. A *convective temperature profile* through a homogeneous medium can be non-linear. In a hydrothermal system of high permeability a conductive temperature profile will often trend towards a *boiling-point for depth* gradient.
Fumarole:	A thermal vent which emits primarily steam but also gases.
Geyser:	A cyclic eruption of water, usually boiling.
Hydrodynamic gradient:	A fluid temperature gradient with depth which exceeds that possible in a hydrostatic situation (*i.e. boiling point for depth*) but remains single phase as the excess energy (and therefore pressure) is loss by friction as the fluid flows upwards.
Hydrofracturing:	Fracturing of rocks when fluid pressure exceeds the minimum compressive stress plus the effective tensile strength of the rock.
Hydrostatic gradient:	Where pressures are determined by the amount of overlying liquid.
Hydrothermal eruption:	An eruption of solid material (and fluid) which reaches the surface and is caused by hydrothermal processes.
Lithostatic gradient:	Where fluid pressures are determined by the confining rock pressure.
Outflow zone:	Area where water is flowing laterally away from an upflow zone.
Permeability:	The ability of fluid to flow through the rock, which depends on the porosity and the degree of interconnection of pores or fractures.
Piezometric surface:	A surface of equal fluid pressure within the rock mass. Usually taken to refer to a theoretical 'water table' based on fluid pressure. Note however that in a steam-dominated zone, the actual water level will be considerably below the piezometric surface.
Porosity:	Proportion of pore space within a rock.
Single phase zone:	A zone in which the pressure gradient corresponds to a single-phase liquid.
Upflow zone:	Area where hot fluid is flowing more or less vertically upwards within a geothermal system.

Hydrothermal fluid physics and chemistry

Adiabatic:	A process which takes place without gain or loss of heat.
Boiling:	Change of state from liquid to vapour which usually takes place vigorously as the fluid has reached saturation temperature at the local confining pressure (in contrast to evaporation, which takes place slowly due to net loss of vapour in an open system).
Condensation:	Change of state from vapour to liquid.
Connate Water:	Water trapped within sediments at the time of their deposition, thus often close to seawater in original composition though later usually modified by water-rock interaction.
Enthalpy:	The heat content per unit mass of a solid, liquid or gas, usually expressed in units of kJ/kg.
Effervescence:	Loss of volatiles from solution. Usually taken to refer to loss of dissolved gases.
Flashing:	Boiling, usually taken to mean in response to pressure reduction.
Henry's Law:	A mathematical relationship describing how the partial pressure of a dissolved gas in water changes with increasing gas concentration.
Incompressible:	An incompressible fluid, such as liquid water, will not change in volume in response to pressure (unlike a gas).
Isenthalpic:	Without gain or loss of energy or work (in contrast to adiabatic processes).
Isentropic:	Without gain or loss of entropy.
Isothermal:	At constant temperature.
Isobaric:	At constant pressure.
Kelvin scale:	A temperature scale in which the degrees are the same size as in the Celsius/Centigrade scale, but which starts from absolute zero. Thus 0 °C = approximately 273 K.
Magmatic fluid:	Water of magmatic origin that is derived from the loss of volatiles from magma.
Meteoric fluid:	Water of surficial origin, including near-surface groundwaters.
NCG:	Non-condensable gas. In the geothermal context this refers to the gases contained in steam which do not condense when the steam condenses, *i.e.* usually mostly CO_2 plus lesser H_2S.
pH:	Negative $\log_{10}$ of the hydrogen ion concentration in a solution. At ambient temperatures pH 7 is neutral, acid solution have a pH of less than 7 and the limit of aqueous alkaline solutions is 14. Note that these values change at elevated temperatures.
Saturation ratio:	The proportion of a two-phase fluid which is made up of water (or steam). It is important to define which you are referring to, and whether it is a ratio by volume or mass (usually the latter).

Saturation temperature/ pressure:	In this context usually refers to the temperature/pressure conditions which are just equal to the theoretical vapour pressure, so that steam and water can co-exist.
Solute:	Something which is dissolved in a solution.
Specific heat:	Measured in Joules. The amount of energy which it takes to raise one gram of the material one degree K.
Storativity:	A measure of the ability of a rock formation to hold and release fluid. The specific storage is the amount of water that a portion of an aquifer releases from storage, per unit mass or volume of aquifer, per unit change in hydraulic head, while remaining fully saturated. It can be defined either on a mass or volumetric basis, but the latter is more commonly encountered in geothermal applications.
Super-critical fluid:	Fluid at a temperature above the critical point, at which only a single phase can exist regardless of pressure. For pure water the critical point is approximately 374°C, but it rises markedly with increasing solute content.
Super-heated:	A vapour (usually referring to steam) which is at a temperature which is hotter than the saturation temperature for the equivalent pressure.
Super-saturated:	A solution which contains more than the saturation quantity of a particular solute. This is a dis-equilibrium condition, which can however persist metastably for some time in certain instances.
Transmissivity:	Transmissivity is a measure of the hydraulic conductivity of a rock formation, that describes the ease with which water can move through pore spaces or fractures.
Two-phase fluid:	Strictly speaking fluid consisting of two separate phases (*i.e.* liquid (water) and gas (steam)). If applied to water, however, it may be referring to a fluid which has an enthalpy between that of steam and water at the appropriate temperature, but which may act as a coherent mass rather than two physically separate phases.
Undersaturated:	A solution which contains less than the saturation quantity of a solute, and can therefore dissolve more.

Systems, projects, power plants and processes

Back Pressure:	Refers to a turbine which exhausts to an appreciable pressure (e.g. atmospheric pressure or a lower-pressure second stage turbine) rather than a partial vacuum.
Binary cycle:	A power plant in which energy is transferred from a primary fluid to a secondary working fluid which is then used to produce work in a turbine.
Condensing:	Refers to a turbine which exhausts to a partial vacuum, maintained by direct or indirect contact cooling to condense the fluid and the extraction of non-condensable gases (if any).
EGS:	Enhanced Geothermal System. A body of rock containing useful energy, the recoverability of which has been increased by artificial means such as fracturing.
Geothermal Combined cycle;	A geothermal power plant with more than one type of unit operating in a sequential or cascaded fashion: the most common arrangement (but by no means the only one possible) is a steam turbine which uses a binary cycle as a condenser, with or without other binary cycles operating on separated brine.
HR:	Hot Rock. A body of rock containing useful energy, but which needs additional fluid artificially added to be able to extract that energy.
Kalina:	Refers to a binary power plant utilising one of the several thermodynamic cycles devised by Prof. A Kalina. They have the common feature of a working fluid which is an azeotropic mixture of two components with different boiling points (normally ammonia and water), thereby changing its composition during boiling and condensation.
OEC:	Ormat Energy Converter. A widely used commercially available binary plant module produced by Ormat Technologies, Inc.
ORC:	Organic Rankine Cycle. A binary cycle using a hydrocarbon working fluid.
Power Output	**'Gross'** output refers to power production within the power plant limits ignoring in-house use and losses such as for cooling fans. **'Net**' output if used in an unqualified way refers to output at the power plant limits, subtracting in-house use but not production nor reinjection pumping nor transmission losses. The difference from gross to net for a typical ORC binary plant would be in the range of 10-20%, but less for a condensing steam turbine. **'Net to Grid'** or **'Net to export'** output refers to power delivered at the project power scheme limits, having subtracted production and reinjection power requirements and losses in the switchyard (which can be expected to be small), but not external transmission losses to the end-user. Pumping requirements will vary greatly from site to site. They can range from zero to in excess of 30% of power produced.
Proppant	A proppant is granular material introduced along with the fluid to prop stimulated fractures open.

Appendix D Assessment and Reporting Criteria

(Table 2 of the Code)

These tables are a checklist and guideline which those preparing reports on Exploration Results, Geothermal Resources and Geothermal Reserves should use as a reference. They are for guidance only and are not formally part of the Geothermal Reporting Code

The checklist is not prescriptive. It is to identify parameters and assumptions used in geothermal exploration/development and to consider each of these from the viewpoint of the disclosure required for transparency & materiality. Relevance and materiality are overriding principles that determine what information should be publicly reported. It is, however, important to report any matters that might materially affect a reader's understanding or interpretation of the results or estimates being reported. This is particularly important where inadequate or uncertain data affect the reliability of, or confidence in, a statement of Exploration Results or an estimate of Geothermal Resources or Geothermal Reserves.

The order and grouping of criteria in Table 2 reflects the normal systematic approach to exploration and evaluation. Criteria in the first group 'Pre-Drilling Exploration Technical Data' may apply to all succeeding groups. In the remainder of the tables, criteria listed in preceding groups would often apply to succeeding groups and should be considered when estimating and reporting. Thus data required in A may also be relevant to B and data in A & B may be relevant to C but that in C, for instance, may not be required for B. In Item D a distinction is made between parameters more relevant to naturally convective hydrothermal reservoirs and deep sedimentary aquifers, and those more related to Hot Rock situations (Enhanced Geothermal Systems (EGS) may draw on both).

A. Pre-Drilling Exploration Technical Data

Parameters listed in this group may be required in all succeeding groups.

Parameter/ Data	Considerations
Geological maps & interpretation	▪ Nature and quality of available mapping (e.g. scale, completeness, age, authors, 2D, 3D etc.) including basis for interpretation and any implications for likely Geothermal Resource types ▪ Description of any relevant Geothermal Plays previously recorded in the vicinity or same geological province
Data location and spacing	▪ Adequacy of base maps ▪ Methodology and quality of sample location (e.g. GPS etc.) ▪ Datums and projections used along with any relevant parameters (locations should be reported using recognised co-ordinate systems and not local grids wherever possible) ▪ Spacing of available data points ▪ Extent of data interpolation/extrapolation including explanation of techniques applied
Evidence for past or present water/rock interaction	▪ Location and description of observed hydrothermal alteration and mineralisation
Hydrology	▪ Nature and quality of near-surface hydrological data and the basis for interpretation including indicators of deeper hydrology
Sampling techniques	▪ Nature and appropriateness of geological, geochemical or fluid sampling procedures including collection, steps taken to ensure samples are representative, sample identification and preservation
Analytical techniques	▪ Identification and experience of analytical laboratory ▪ Nature, quality and appropriateness of laboratory techniques and related quality control procedures (e.g. in determination of petrographic, geochemical, fluid or gas analysis, physical rock properties, isotope, age data etc.) ▪ The level of analytical uncertainty and whether acceptable levels of accuracy and precision are considered to have been established
Temperature measurement & geothermometry	▪ Nature and quality of available surface temperature data (e.g. ambient, 1m probe, aerial infra red scans, existing shallow wells etc.) ▪ Nature, quality and appropriateness of techniques used to determine temperatures from fluid or rock chemical geothermometry, including source of fluids, level of uncertainty in measurement and key assumptions made. ▪ Nature of thermal features used to determine temperature and their relation to chemical sampling
Temperature gradient	▪ Nature, quality and appropriateness of calculations used to determine temperature gradient including the nature and source of surface temperature data and the associated level of uncertainty ▪ Depth intervals of determined gradients

Thermal conductivity (K)	▪ Whether determined analytically, modelled or assigned ▪ Where determined analytically, identification and experience of analytical laboratory and nature, quality and appropriateness of analyses used (e.g. number and frequency of samples, technique used to determine K, type of samples (e.g. core etc.), sample preparation (e.g. sample dimension, polish etc.) and analytical specifications (e.g. orientation of samples, wet or dry analysis, temperature at which K was determined etc.) ▪ Where modelled, the nature, quality and appropriateness of the model used, the source and quality of input parameters, corrections applied and/or key assumptions made ▪ Where assigned, the basis for interpretation including key assumptions and data sources ▪ The estimated level of uncertainty
Heat flow	▪ Whether based upon measured or assumed parameters ▪ Where based on measured data, then nature and quality of the measurements (temperature & thermal conductivity), including characteristics of any thermal features from which they were derived, frequency and distribution of the samples, methods used for depth matching temperature and thermal conductivity data, assumptions made and any evidence of temporal change ▪ Where reliant upon assumed or assigned data, then the basis for interpretation, including key assumptions and data sources ▪ In all cases nature, quality and appropriateness of the models used (e.g.1D, 2D or 3D modelling), corrections applied and key assumptions made regarding physical conditions, vertical heat flow, topographic models etc. ▪ The estimated uncertainty including key assumptions made
Heat generation determination	▪ Basis for the identification of significant sources of subsurface heat generation ▪ Nature, quality and appropriateness of model used to calculate heat generation capacity and the level of uncertainty in the results
Geophysical techniques	▪ Nature, quality and appropriateness of any geophysical techniques used to describe or define geothermal anomalies including uncertainty and key assumptions made before, during and after interpretation, modelling, calibration of rock properties especially with drill hole data, contractors used and available survey parameters (e.g. resistivity, seismic, gravity, magnetic, MT) for both regional and local surveys
Data integrity and verification	▪ Measures taken to ensure data have not been corrupted between initial collection and use in models/calculations ▪ Data validation process ▪ The verification of significant results by application of alternative techniques and/or independent personnel

B. Tenement, Environmental and Infrastructure Data

Parameters listed in the preceding group apply where relevant. Parameters listed in this group may be required in all succeeding groups. Information in this group in particular may require updating and re-issuing at later stages in the development process.

Parameter/Data	Considerations
Tenement and land tenure status	▪ Type, reference name/number, location and ownership including agreements or material issues with third parties such as joint ventures, partnerships, overriding royalties, native title interests, historical sites, wilderness or national park and environmental settings ▪ The security of tenure held at the time of reporting along with any known impediments to obtaining a licence to operate in the area
Terrain, geotechnical issues and access	▪ Identification of significant geotechnical, geohazard or access issues which could affect future drilling locations or sterilise sectors
Environmental issues	▪ Identification of significant environmental issues (for instance example, water, seismicity) which could affect future drilling locations or sterilise sectors
Land use issues	▪ Identification of significant land use conflicts which could affect future drilling locations or sterilise sectors
Infrastructure	▪ Proximity to and quality of relevant infrastructure and water supply, in particular transmission lines when the project is being considered for electricity generation
Exploration by other parties	▪ Acknowledgment and appraisal of exploration by other parties to the extent the data are available

C. Subsurface and Well Discharge Data

Parameters listed in the preceding group apply where relevant. Parameters listed in this group may be required in all succeeding groups.

Parameter/ Data	Considerations
Drilling data	▪ Type of drilling used (e.g. core, rotary etc.) including basic spud/collar details (e.g. date drilled, depth etc.) ▪ Availability of drilling records and data from rig instrumentation (e.g. ROP, WOB, circulation losses, mud logging, drilling breaks, well kicks etc.) ▪ Nature and quality of directional survey data ▪ Type of completion used and related details (e.g. depth to casing etc.)
Well sample recovery	▪ Nature and quality of down-hole samples (e.g. cuttings, core, fluids etc.) and sampling intervals including the basis for determination of sampling depths and measures taken to ensure samples are representative
Geological log	▪ The nature and scale of logging as well as the basis for geological interpretation and identification of alteration zones (e.g. qualitative vs. quantitative logs, lithology, palaeontology, palynology, mineralogy, fluid inclusions, Vitrinite reflectance etc.) ▪ Whether there is any evidence from mineralogy indicating acid or high-gas fluids
Downhole temperature pressure and flow logs	▪ Nature (e.g. continuous log, maximum recording thermometer, injectivity test, Pressure Build Up etc.), quality (e.g. tool precision, operating parameters, time allowed, resolution, type and frequency of calibration) and appropriateness (e.g. tool operating parameters relative to hole conditions, tool resolution, processing or corrections required and/or applied) of instrument/s used ▪ Characteristics and quality of measurement(s) (depth, frequency, timing, precision, accuracy etc.) including level of uncertainty ▪ Appropriateness of interpretation with consideration for all significant influences (e.g. presence of local aquifers or known fluid circulation, well status at time of logging (e.g. shut in, flowing, injection rate etc.) ▪ Nature and quality of any temperature corrections applied or justification for neglecting correction (e.g. length of time elapsed between drilling and temperature measurement) ▪ If no corrections are applied and the measured temperature is likely to be affected by the drilling thermal anomaly this must be clearly stated
Other downhole logging	▪ Nature (e.g. FMI, Gamma, calliper etc.), quality (e.g. tool precision, operating parameters, resolution, type and frequency of calibration) and appropriateness (e.g. tool operating parameters relative to hole conditions, tool resolution, processing or corrections required and/or applied) of instrument/s used ▪ Nature and quality of measurement(s) (depth, frequency, timing) ▪ Appropriateness of interpretation with consideration for all significant influences (e.g. hole condition, temperature, formation invasion etc.)
Aquifers	▪ Location of permeable zones/aquifers, their significance and relationship to structures and stratigraphy ▪ Nature, quality and appropriateness of model/s used to determine adjusted heat flow
Depth of reservoir	▪ Depth of anticipated reservoir development

Injection tests	▪ Nature and quality of injectivity tests conducted across permeable zones ▪ Nature (e.g. calculated or observed, flow versus wellhead pressure) and appropriateness of determined injection capacity of well including key assumptions and temperature data ▪ Any evidence of temporal change
Multi-well tests	▪ Nature (e.g. circulation, interference, tracer etc.) and quality of well tests and measurements, including duration and sampling methods where relevant ▪ Appropriateness of test interpretation including any corrections or omissions and any evidence of temporal variation
Well discharge testing	▪ Nature (e.g. James method, separator and orifice plates, Tracer Dilution Flow Test etc.) and duration of tests (including completeness of the measurement suite over the wellhead pressure discharge curve) ▪ Quality and reliability of monitoring equipment ▪ Characteristics observed over time including any chemical and/or physical indications of dilution by drilling fluids, stability, multi-zone behaviour, possible scaling or dry-out, tracer returns

D1. Naturally Convective Systems and Hot Sedimentary Aquifer Resource Parameters

Parameters listed in the preceding groups apply where relevant. Parameters listed in this group apply to all succeeding groups where relevant.

Parameter/ Data	Considerations
Flow rate	▪ Nature (e.g. individual vs. interference, duration, depth etc.), quality and appropriateness of techniques used to record flow rates in wells together with key assumptions made ▪ Where rates are derived from individual well tests these must be detailed individually and must not be summed except with suitable acknowledgement of possible interference ▪ Magnitude and uncertainty of temperature and pressure drawdown observed during flow tests, in relation to chemical indications of stability and long term trends
Pressure data	▪ Nature, quality and appropriateness of techniques used to determine reservoir pressures including multi-well correlations, fluids and key assumptions made
Recharge	▪ What allowance (if any) has been made for heat and fluid recharge, and the basis thereof
Water saturation and enthalpy	▪ Nature and appropriateness of techniques used to determine *in-situ* water saturation ▪ Nature and quality (e.g. accuracy) of measurements of well discharge enthalpy including consideration of how they relate to in situ saturation
Scaling, gas content composition and acidity	▪ Data on reservoir fluid chemistry and its impact on the reservoir, wells and surface facilities ▪ Nature and appropriateness of tests carried out to determine surface and down hole scaling potential of fluids including the basis for interpretation of test results ▪ Nature and appropriateness of tests run, models applied or analogies used as evidence for possible offset of scaling by methods of downhole or surface inhibition
Reservoir properties	▪ Nature, quality and appropriateness of methods used to determine reservoir properties (rock types, porosity, permeability, anisotropy, specific permeable structures etc.) ▪ Basis for interpretation of temperature and pressure profiles
Conceptual model: nature of the system	▪ Nature, quality and appropriateness of integrated geo-hydrological reservoir model including analogies used and key assumptions made ▪ Whether the fluid is naturally convecting ▪ If the project is based on a laterally extensive aquifer, what are its hydrological properties outside the concession area ▪ Interpretation of physico-chemical reservoir processes
Numerical modelling	▪ Nature of numerical simulation modelling, including model structure, key parameters, boundaries and relationship to conceptual modelling ▪ Results of natural state modelling ▪ Result of history matching (if any) ▪ Results of forecast runs including descriptions of scenarios modelled ▪ Sensitivity analysis and the effects of alternative interpretation
Data extrapolation	▪ The extent of data interpolation/extrapolation including explanation and justification of techniques applied

D2. Hot Rock Resource Parameters

Parameters listed in the preceding groups including D1 apply where relevant. Parameters listed in this group apply to all succeeding groups where relevant.

Parameter/ Data	Considerations
Lithology	▪ Nature, condition and volume of reservoir target
Fluid conditions	▪ Whether any naturally occurring fluids exist in the target reservoir rocks and if so what is their chemistry ▪ Whether external water sources will be required as the medium to remove the heat contained in the rocks
Stress condition	▪ Nature, quality and appropriateness of available stress measurements ▪ Number, spacing and depth of available stress measurements
Natural fractures	▪ Nature, quality and appropriateness of data (orientation, location, frequency) regarding the natural fracture network including knowledge of flowing fractures, their depth and relevance to the reservoir development ▪ Fracture character including aperture, width, mineral content and surrounding cataclastic zone
Reservoir stimulation	▪ Nature, location and frequencies of reservoir stimulation events ▪ Corresponding pressure/flow data, including basis for interpretation and displaying temporal variations ▪ Quality and reliability of monitoring equipment
Micro-seismic monitoring	▪ Nature, quality and appropriateness of seismic network used to monitor reservoir stimulation (e.g. instrumentation, distribution, locational accuracy, sensitivity, resolution, check shot etc.) ▪ Volume estimation of the derived reservoir including key assumptions made and estimation of uncertainty ▪ Evidence for achievement of stimulated reservoir volume

E. Reporting of Exploration Results

Parameters listed in the preceding group apply where relevant. Parameters listed in this group may be required in all succeeding groups.

Parameter/ Data	Considerations
Diagrams	▪ Where possible, maps and sections (with scales) and tabulations of intercepts should be included for any material discovery being reported if such diagrams significantly clarify the report ▪ Diagrams and maps should be presented using recognised coordinate systems with datums, projections and all relevant parameters declared on the map face
Balanced reporting	▪ Where possible reporting should be comprehensive ▪ Where comprehensive reporting of all Exploration Results is not practicable, representative reporting should be practiced to avoid misleading reporting of Exploration Results
Other substantive exploration data	▪ Other exploration data, if meaningful and material, should be reported including (but not limited to): geological observations; geophysical survey results; geochemical survey results; groundwater; geotechnical and rock characteristics; potentially deleterious or contaminating substances
Audits or reviews	▪ The results of any audits or independent reviews of exploration data, models or interpretations
Further work	▪ The nature and scale of planned further work (e.g. tests for lateral extensions or depth extensions or large-scale step-out drilling).

F. Estimation and Reporting of Geothermal Resources

To be considered in conjunction with previous tables when reporting results of Geothermal Resource estimate.

Expected use	▪ Nature of the anticipated Geothermal Resource exploitation including any assumptions made
Data integrity	▪ Source and reliability of all relevant Geothermal Resource data ▪ Measures taken to ensure data described has not been corrupted between initial collection and use in models/calculations ▪ Data validation process
Data interpretation	▪ Confidence in (or conversely the uncertainty of) any interpretation of geological, geophysical or geochemical data to be used in the Geothermal Resource estimation ▪ The effect, if any, of alternative interpretation/s upon Geothermal Resource estimation
Well deliverability	▪ Must be demonstrated if Geothermal Resource/s to be regarded as Measured ▪ Whether the project will rely on pumping or self-discharging wells ▪ Information on expected parasitic power requirement for production or injection pumps
Estimation and modelling techniques	▪ The nature and appropriateness of the estimation technique(s) applied and key assumptions made ▪ The availability of previous production records and whether such data is considered ▪ Any assumptions regarding the correlation of variables ▪ The process of validation, the checking process used and the reconciliation of model to measured data and the verification of significant results by application of alternative techniques and/or independent personnel
Cut-off parameters	▪ The basis for any adopted cut-off temperatures, flow rates or quality parameters (e.g. reservoir porosity, well deliverability etc.) applied, preferably related to a known technology pathway
Recovery factors	▪ Must be explicitly stated and justified
Conversion efficiency	▪ If used, expected conversion efficiency for converting heat into electricity ▪ Methodology used for determination of conversion efficiency including an explanation of the technology pathway and justification of any assumptions made
Dimensions	▪ The extent and variability of the estimated Geothermal Resource expressed as surface area and depth below surface including a explanation of the basis for any interpretations of reservoir geometry
Geothermal Resource Life	▪ The expected life of the Geothermal Resource based upon available modelling and anticipated development ▪ Nature, quality and appropriateness of methods used for Geothermal Resource-life modelling including key assumptions ▪ Estimation of deleterious elements (e.g. short circuiting, scaling etc.)

Classification	▪ The basis for the classification of the Geothermal Resource into varying confidence categories ▪ Whether appropriate account has been taken of all factors ▪ Whether the results appropriately reflect the views of the Competent Person
Third party involvement	▪ Acknowledgement of possibly conflicting developments by other parties
Audits or reviews	▪ The results of any audits or reviews of the Geothermal Resource estimate
Balanced and impartial reporting	▪ Where possible reporting should be comprehensive ▪ Where comprehensive reporting of all Geothermal Resource estimation is not practicable, representative reporting should be practiced to avoid misleading reporting of Geothermal Resource estimation
Discussion of relevant accuracy/confidence	▪ Where appropriate a statement of the relative accuracy and/or confidence in the Geothermal Resource estimate using an approach or procedure deemed appropriate by the Competent Person. For example, the application of sensitivity analysis, probabilistic analysis or use of scenario trees, or, if such an approach is not deemed appropriate, a qualitative discussion of the factors which could affect the relative accuracy and confidence of the estimate ▪ The statement should specify whether it relates to the whole or partial Geothermal Resource and, if partial, clearly state the extents along with assumptions made and procedures used ▪ These statements of relative accuracy and confidence of the estimate should be compared with production data, where available
Qualifications and accountability	▪ A statement of the qualifications, experience and accountability of the Competent Person making the estimate

G. Estimation and Reporting of Geothermal Reserves

To be considered in conjunction with previous tables when reporting results of Geothermal Reserves estimate.

Resource estimate for conversion	▪ Description of Geothermal Resource estimate to be used as a basis for conversion to a Geothermal Reserve, including data sources and justification for all assumptions made ▪ Clear discrimination between Geothermal Resources reported as additional to Geothermal Reserves and those included within the Geothermal Reserves
Study status	▪ The type and level of study undertaken to enable the Geothermal Resource to be converted to Geothermal Reserve
Plant when related to electricity generation	▪ Technology to be used and demonstration of technical viability if novel ▪ Expected capacity and life of associated power plant development ▪ Expected plant factor including key assumptions in determination

Environmental and land use	▪ Identification of any significant environmental factors or land use conflicts which sterilise sectors or impact on project economics including, but not limited to:
	  ▪ Third party development
	  ▪ Emissions to air or water
	  ▪ Subsidence
	  ▪ Effect on groundwater
	  ▪ Effects on natural thermal activity or ecosystems
	  ▪ Changes in surface heat flow, induced hydrothermal eruptions
	  ▪ Induced seismicity
	  ▪ Effects on tourism, bathing or other land uses

Cost and revenue factors	▪ The derivation of, or assumptions made, regarding projected capital and operating costs ▪ The assumptions made regarding revenue ▪ The allowances made for royalties payable
Market assessment	▪ Location of the Geothermal Resource relative to the expected market ▪ Market capacity vs. price ▪ Where applicable, the electricity price used, including the basis for assuming this value, its estimated uncertainty and the effects of any uncertainty upon the Geothermal Reserve estimation
Other	▪ The effect, if any, of natural risk, infrastructure, legal, social or governmental factors on the likely viability of the project ▪ The status of titles and approvals critical to the viability of the project
Classification	▪ The basis for the classification of the Geothermal Reserve into varying confidence categories ▪ Whether appropriate account has been taken of all factors ▪ Whether the results appropriately reflect the views of the Competent Person
Audits or reviews	▪ The results of any audits or reviews of the Geothermal Reserve estimate

Discussion of relevant accuracy/confidence	▪ Where appropriate a statement of the relative accuracy and/or confidence in the Geothermal Reserve estimate using an approach or procedure deemed appropriate by the Competent Person. For example, the application of sensitivity analysis, probabilistic analysis or use of scenario trees, or, if such an approach is not deemed appropriate, a qualitative discussion of the factors which could affect the relative accuracy and confidence of the estimate ▪ The statement should specify whether it relates to the whole or partial Geothermal Reserve and, if partial, clearly state the extents along with assumptions made and procedures used ▪ These statements of relative accuracy and confidence of the estimate should be compared with production data, where available
Qualifications and accountability	▪ A statement of the qualifications, experience and accountability of the Competent Person making the estimate

H. Additional Factors: Existing Developments

To be considered in conjunction with previous tables. The purpose of this section is to account for previous Geothermal Resource extraction and to use production data to better characterise future Geothermal Reserve estimation.

Production data	▪ Production data on past total heat and fluid extraction and reinjection ▪ Pressure, temperature, enthalpy and chemical historical trends both for individual wells and the whole Geothermal Resource, together with any interpretations in terms of reservoir processes and the hydrogeolgical conceptual model ▪ Any assessments of heat and fluid recharge

Reservoir monitoring	▪ Methods used and an assessment of data quality for reservoir monitoring, including but not limited to:
	  ▪ Surface and downhole pressure and temperature measurements
	  ▪ Fluid flows and enthalpy measurements
	  ▪ Tracer tests
	  ▪ Well output tests
	  ▪ Thermal activity and heat flow monitoring
	  ▪ Ground deformation monitoring
	  ▪ Microgravity monitoring
	  ▪ Environmental monitoring

Production history	▪ History of Geothermal Resource usage including numbers and locations of wells used for production and reinjection, especially in relation to observed reservoir changes
Numerical modelling	▪ Numerical simulation modelling should be used at this stage as soon as sufficient production history is available to do so in meaningful fashion ▪ Good history matchings should be achieved for credibility ▪ Should include a detailed description of all scenarios modelled and bear a close relationship to the actual existing or proposed development scheme
Development scenarios	▪ Future Geothermal Resource usage scenarios

Appendix E: Acknowledgements

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