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Proven Geothermal Technologies Provide Clean, Reliable Power

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ABSTRACT

This paper describes the technologies and field proven experience with various geothermal binary and combined steam/binary power plants utilizing both water and steam dominated resources having low, moderate or high enthalpy.

The key to an economic and successful project is the cost effectiveness of the complete plant, as measured in the actual cost of production. Only proven technologies can effectively produce reliable electricity at a predictable cost to the project developers, operators and investors. In geothermal flashed steam plants, many innovative power cycles have been proposed in the last 20 years; but only four are in proven commercial operation, these are: single- and double-flash steam cycle, the super-critical binary, the cascade binary and the combined steam and binary. Operational experience has confirmed the advantages of the binary plants, not only for the low enthalpy water-dominated resources, but also at high enthalpy, or in case of aggressive brine, for low environmental impact and for long term resource management considerations.

The implementation of new geothermal plants still faces hurdles, in particular in financing.

1. INTRODUCTION

Geothermal Power Production is a mature and competitive industry, which has benefited from continuous improvement in plant design and technology transfers from the oil and gas industry.

Today the worldwide installed capacity is more than 8000 MWe and the potential (not including Hot Fractured Rock) is estimated at 60,000 MWe.

Geothermal energy provides significant environmental benefits such as a small footprint and low CO_2 emissions (Fig.1). However local impacts must be identified and dealt with.

Over the last two decades the efficiency of the power plants has substantially improved (Fig.2). This paper will focus on the progress of ORMAT's binary and combined cycle experience over the last two decades.

2. DRIVERS FOR THE DEVELOPMENT OF GEOTHERMAL ENERGY

Geothermal energy, although site specific, exists in many otherwise energy poor countries which rely on imported fuel for their power generation.

The combination of non-fossil fuel and power generation from indigenous geothermal resources results in social,

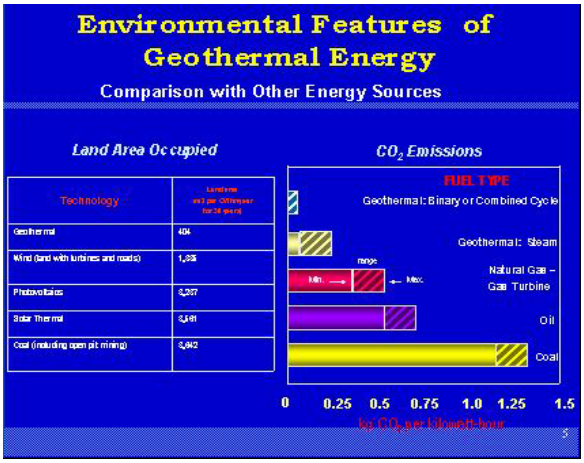

Figure 1

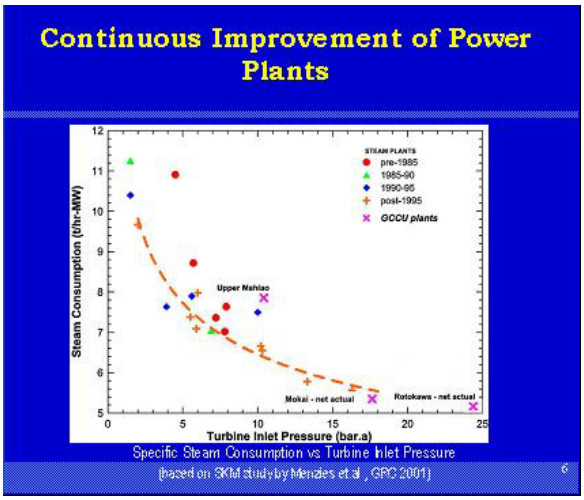

Figure 2

economic and technical benefits. Geothermal projects can make good economic sense since their power costs are competitive with diesel generation, and often can provide power at lower real cost when compared to electricity produced from imported fuel.

In addition geothermal energy projects inherently bring technology transfers to the host developing countries such as the Philippines, Kenya, Mexico and Indonesia, where local technical teams drill wells, construct and operate power plants and manage the complex geothermal reservoirs.

The need to diversify from reliance on hydro and fuel imports is another driver for many countries.

3. GEOTHERMAL APPLICATIONS OF BINARY CYCLE CONFIGURATIONS:

3.1 Liquid Phase Directly from Wells

This application of binary cycle for liquid resources relates to temperatures too low to make flashing into steam worthwhile or resources too small to make a steam turbine economical.



Figure 3: Rogner Bad Blumau, Austria

The binary cycle power unit in the Hotel and Spa Rogner in Bad Blumau, Austria, in 2001 and all the geothermal power plants installed by ORMAT in Nevada and California from 1986 to 1994 – e.g. Wabuska, Steamboat, Soda Lake I and II, Ormesa Complex (4 plants), Stillwater, and Heber were of this type.

Theoretically it is possible to generate power from hot water sources of even below 100°C, and ORMAT has such experience. However, for economic viability 110°C may be considered the lowest feasible temperature, but this figure also depends on the temperature to which it is possible to cool the fluid owing to its particular chemical characteristics and the economic parameters of the project.

3.2 Brine From Separators

This application is technically identical to the previous one. Many geothermal steam plants do not currently utilize the separated brine and waste the energy due to unfamiliarity with the technology, uncertainty on the stability of the brine flow rates or concerns about scaling problems in the reinjection wells if the brine is cooled in a binary cycle power unit.

However, experience shows that this application is very practical and feasible and that techniques exist to satisfactorily cope with scaling problems in most resources –such as acid injection to reduce the pH of the brine.

By exploiting the heat energy in the brine, many projects may be able to gain an additional 20-30% output from the same wells, depending on the chemistry of the brine.

Examples of OEC's installed for separated brine utilization include Kawerau I and II in New Zealand and Momotombo in Nicaragua (Fig. 4).

3.3 Two-Phase flow with High Liquid Fraction

There are a number of resources of a low-medium enthalpy 2-phase flow which traditionally would be developed using condensing steam turbines with low turbine inlet pressures of 2 bara to say 4.5 bara. It can be demonstrated that for



Figure 4: Momotombo, Nicaragua

such resources a two-phase binary cycle unit - where the steam would enter the vaporizer and the separated brine the preheater of a single binary unit - would be the most thermodynamically efficient and cost-effective solution.

In general, such a configuration would be optimal at higher wellhead pressures, so that a higher output could be achieved with less mass flow, less piping and fewer injection wells. The higher wellhead pressure would assist in reducing the risk of scaling in the production wells and the smaller mass flow per kW output obviously enhances the sustainability of the resource.

Such equipment has been utilized at ORMAT plants in Ngawha, New Zealand (12 MW), Sao Miguel A & B in Azores, Portugal (14 MW), Zunil in Guatemala (24 MW) and Olkaria III in Kenya (Phase I – 13.6 MW).

The Two-Phase OEC also has applicability to small scale projects of the 1 to 10MW range where one or two low producing wells could be cost-effectively utilized with this technology, whereas a conventional steam turbine plant would be both prohibitively expensive and unable to exploit the brine.



Figure 5: São Miguel, Azores

An example of this type of plant is the 14 MW São Miguel, Azores, plant which was developed in two phases of 5.5 MW and 8.5 MW several years apart. The design point conditions are given below:

Steam Flow Rate:	127.8 tons/hr
NCG in steam (by weight):	7.5%
Steam Inlet Pressure:	5.1 bara
Brine Flow Rate:	412.1 tons/hour
Brine Inlet Temperature:	153°C
Ambient Air Temperature:	13°C

Figure 5 shows a view of the São Miguel plant after completion of the second phase.

3.4 Use of Steam-Binary Combined Cycle (GCCU) to Better Cope with High-Pressure Steam Dominated Sources:

For higher pressure steam resources, depending on the nature of the flow rate vs. well head pressure curve, the Geothermal Combined Cycle Unit may provide equal or greater output than a conventional steam turbine, which is designed to operate in a narrower range of steam pressures. A conventional turbine will have a problem of wetness in the latter stages of the turbine if the inlet pressure is too high. There is no such problem in the GCCU. The higher the steam pressure, the more advantageous is the GCCU.

Furthermore, the problem of wetness in the last stages in a conventional steam turbine is exacerbated when the condensing temperature is lower, thereby presenting a limiting factor to the condensing temperature. This problem obviously does not exist with an organic turbine where low ambient temperatures serve to improve efficiency.

An example of such a high pressure steam power plant is the Rotokawa power plant in New Zealand, whose design point operating conditions for the turbine inlet of the GCCU are given below:

Steam Flow Rate: 133.56 tons/hr (including NCG)
Steam Dryness: 99.98%
Steam Pressure: 23.24 bara
Ambient Air Temperature: 11°C

Besides offering the possibility of better thermodynamic performance with high pressure steam, the GCCU is also applicable to resources with high NCG, since there is no parasitic load associated with removal of the NCG from the system.

ORMAT's experience in combined cycle systems derives from the following projects - Puna, Hawaii (30 MW - 1992), Upper Mahiao, Leyte (125 MW - 1996), Rotokawa, New Zealand (27 MW - 1997) and Mokai, New Zealand (60 MW - 1999).

A view of the Mokai plant can be seen in Figure 6.



Figure 6: Mokai

The range of units produced is from 200 kW low temperature (about 100ºC) for off-grid or combined heat and power units to utility-size units such as the 60 MW Mokai I modular combined cycle plant operating at 18.5 bar with a net steam rate of 5.42 ton/MWh.

4. CONTINUOUS IMPROVEMENT

Over the years the efficiency of ORMAT turbines was improved, reaching 90%. The unit size was also increased, currently reaching 10 MW per turbogenerator.

For high enthalpy resources the geothermal combined cycle plants (back pressure steam turbine with an ORC bottoming unit) are more competitive because of their specific steam consumption (Fig. 7). During the last decade ORMAT supplied equipment for 200 MW of such combined cycle plants. These plants have already saved more than 7 million tons of fuel and avoided the emission of 17.5 million tons of CO_2.

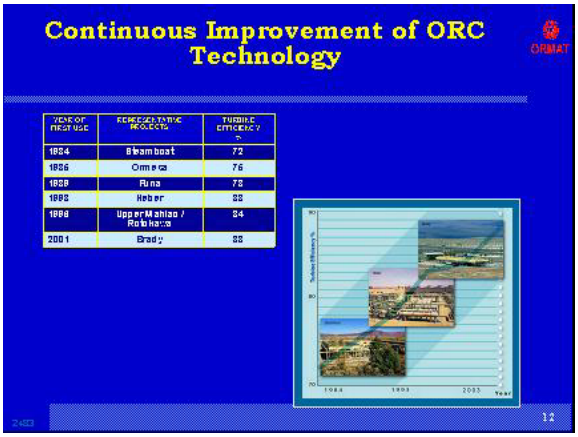

Figure 7

5. CONSTRAINT OF GEOTHERMAL POWER DEPLOYMENT IN DEVELOPING COUNTRIES

Geothermal energy is cost-effective in the market place when it is possible to overcome the discrimination against its capital-intensive nature and the difficulty of characterizing the resource prior to major financial commitment. Barriers to market penetration arising from a general lack of public awareness and experience with the technologies and the social and environmental barriers linked to the lack of experience with planning, regulation and gaining public acceptance must also be surmounted. Geothermal energy has significant positive environmental benefits on the global scale.

Finance-oriented, portfolio-based models should be promoted to take advantage of renewables in the generation mix (to hedge oil price risk). For example, in Mexico at 95% portfolio risk (standard deviation) adding to the mix 11% geothermal and 9% wind reduces the expected generation cost from 4.76 to 3.7 cents/kWh (increases portfolio return from 0.21 to 0.27 kWh/cent) adjusted for the same risk.

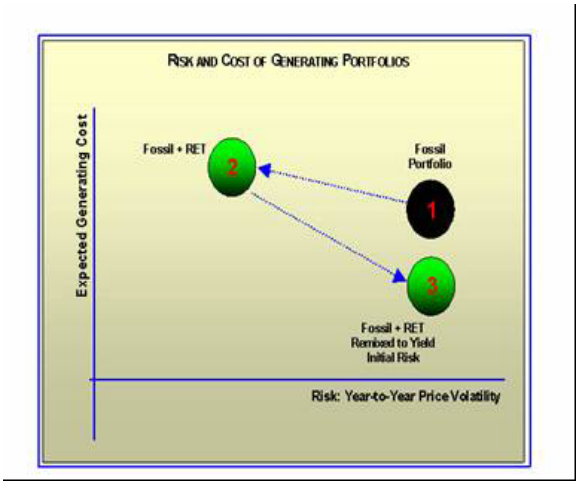

Figure 8: Risk Adjusted Cost

6 HURDLES AND BARRIERS FACING DEPLOYMENT

6.1 Barriers

Commercial financing barriers result from the higher up-front costs of geothermal energy projects. The cost of fossil fuel thermal power includes the power plant capital cost and a per unit fuel cost, while in geothermal projects the capital cost includes the well field development and power plant equipment for delivering and converting natural geothermal energy into electrical power for the lifetime of the project. As a result the front-end capital cost for a geothermal project is much greater than the comparable cost for a fossil fuel project of the same size. Commercial institutions view this as increasing the project's financial risk profile.

Credit risk barriers are particularly prevalent in geothermal energy projects located in developing countries. As a result countries, which can benefit the most from renewable projects, are often the least attractive to the financing institutions.

Institutional barriers may exist in developing countries due to national policies under which fossil fuel power is traditionally sold to a population with low earnings at subsidized prices. As a result the actual cost of geothermal energy is often compared with the artificially low price of subsidized electricity.

6.2 Financing Issues

Multilateral agencies with expensive and time-consuming structured procedural requirements are often the only source available for financing rural electrification and geothermal power projects in emerging markets. In addition, since these geothermal power projects are small compared to fossil fuel plants they often cannot receive the allocation of manpower from the agencies, which focus on large power projects.

Financing costs, procedures and timetables are usually geared for large national projects. This imposes costly time consuming hurdles on the smaller geothermal energy projects. Financing expenses, especially if more than one multilateral agency is involved, are often the same, in total amount, as for the large fossil fuel projects, and are thus disproportionate in size for the smaller geothermal projects.

Statutory limitations on the share of the financing that single agencies can subscribe to, usually 30 to 35%, necessitates that two or more agencies must work together, each with its own specific procedures, which often creates additional complications and delays.

Review standards for small geothermal projects, with innovative technologies, are often more stringent and time-consuming than for well defined large fossil fuel plants. Delays in the extensive financing process may affect national goals and in fact weaken the project's feasibility.

Public Private Partnerships are an efficient way to accelerate the implementation and provide efficient operation and technology transfer.

Unfortunately, in some cases the internal competition between Public Sector and Private Sector departments in the Multi Lateral Institutions slow down the process. It is therefore important to compare the costs of public and private finance (Fig. 9) and assure a division of tasks that would optimize the process. A very good example of a successful policy is the Philippines where the resource development was done by the public sector and the private sector financed the energy conversion under a BOT scheme.

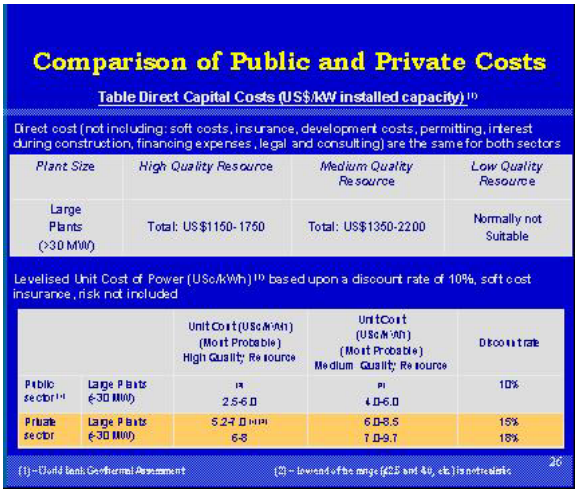

Figure 9

7. CONCLUSIONS AND RECOMMENDATIONS

7.1 Key Factors of Success for Public – Private Partnerships

Governments, multilateral and bilateral agencies should recognize that geothermal energy power projects cannot be evaluated by the same criteria as standard fossil fuel projects, due to: (a) the typically small size of geothermal energy projects; (b) the significant up-front investment to secure the plant's fuel over the project's life; (c) the credit risk barrier encountered by developing countries, and (d) the new, different and innovative technologies which are employed. To enable private companies to play an expanding role in the development of geothermal energy projects, the following steps should be taken:

1. **To encourage the development of geothermal energy power projects,** with commitments to the environment and the reduction of CO_2 emission, such as the WB Carbon Fund and CDM. Subsidies to fossil fuels should be reduced, and redirected to investments in distributed sustainable energy systems where possible.

2. **To accelerate, and significantly reduce the transaction costs** of geothermal energy power projects, multilateral and institutional financing agencies should:

- Apply a standard contract for each type of renewable energy source, and
- Adopt a "one-stop" financing approach.

3. **To facilitate geothermal projects, regulatory agencies** should recognize that:

- Finance-oriented risk adjusted portfolio-based models should be used for generation mix planning.
- A power sector structure based on merchant plants, dispatched according to power costs, is not compatible with the development of geothermal power plants, since the up-front investment in the geothermal energy resource must be recovered on a continuous basis.
- Power cost can be reduced if the resource development is done in the framework of the Public Sector Financing and the Private Sector assures the construction, efficient operation and technology.
- The use of new technologies should not be inhibited by micromanaging project specifications. Developers and manufacturers should be encouraged to take advantage of proven experience and track records by introducing new technologies.

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