Paper 08GM0209

IEEE POWER ENGINEERING SOCIETY
ENERGY DEVELOPMENT AND POWER GENERATION COMMITTEE

Developments in Geothermal and Hydro Power in Iceland, Europe and Worldwide

Tom Hammons and Arni Gunnusson

Working Group on European Electricity Infrastructure[1]

Sponsored by: International Practices for Energy Development and Power Generation

2008 IEEE PES General Meeting, July 20-24 2008, Pittsburgh, PA, USA
Monday, July 21 2008, 2-6 p.m. (Any Unforeseen Change to be Notified in Preliminary/Final Program and by Letter)

Sponsored by: International Practices for Energy Development and Power Generation

Chairs: Tom Hammons, University of Glasgow, Scotland, UK
Arni Gunnarsson, Landsvirkjun (The National Power Company of Iceland), Reykjavik, Iceland

Track: Utilization of Energy Resources

INTRODUCTION

The IEEE PES Energy Development and Power Generation Committee, International Practice Subcommittee, welcomes you to this Panel Session on Development in Geothermal and Hydro Power in Iceland, Europe and Worldwide.

During the last 5-10 years, the development of sustainable geothermal and hydropower resources in Iceland has been the most intensive in Europe. A total of about 1250 MW has been developed and some 1300 MW are to come on line within the next decade. Recent projects include the 700 MWe Karahnjukar Hydroelectric Project and the first phases of the 400 MW Hellisheidi Geothermal Scheme.

The Iceland Deep Drilling Project is a long=term research program to improve the efficiency and economics of geothermal development. Its aim is to generate electricity from natural super-critical hydrous fluids obtained at drillable depths of 4-5 km. A deep well producing fluids at temperature above 450`C could yield up to tenfold power as compared to a conventional geothermal well.

The rapid development of renewable power resources in Iceland has lead to intensive debate on taxation and royalties for utilization of the resources.

Recent price structure changes to enhance green power in Germany are a driving factor in the development of geothermal medium temperature resources, mostly in Southern Germany.

[1] Document prepared and edited by T J Hammons

This Panel Session presents and discusses the current state of developments in harnessing geothermal and hydropower for medium and large-scale generation of electricity and for space heating worldwide. Panelists will review potential and current developments and probable and possible developments both in developed and developing countries in near future and long term. Topics discussed will include challenges during construction and completion of the Karahnjukar 700 MWe Hydro Power Project in NE-Iceland, deep drilling projects in Iceland--exploration of deep unconventional geothermal resources, the phases of development of a 400 MWe generation capacity Geothermal Scheme in NE Iceland, geothermal development in reducing CO2 emissions, and perspectives on the future of geothermal energy in the United States. Technology of harnessing geothermal power now and future will also be discussed. The economics, availability, and reliability of geothermal plants will be reviewed. Transmission of geothermal power from remote locations to populous load areas will be reviewed.

The Panelists and Titles of their Presentations are:

1. Guðmundur Pétursson, Head of the Project Management, Landsvirkjun, Reykjavik, Iceland. The Karahnjukar 700 MWe Hydro Power Project in NE-Iceland: Challenges During Construction and the Completion Phase (Invited Panel Presentation Summary 08GM1646)
2. Björn Stefánsson, Head of Power Projects Department, Landsvirkjun, Reykjavik, Iceland. Deep Drilling Project, Exploration of Deep Unconventional Geothermal Resources (Invited Panel Presentation Summary 08GM1207)
3. Allan Jelacic, Acting Program Manager, Geothermal Technologies Program, US Department of Energy, Washington, DC, USA and Joel L. Renner, Idaho National Laboratory, US Department of Energy, USA. A Perspective on the Future of Geothermal Energy in the United States (Invited Panel Presentation Summary 08GM1654)
4. Lucien Y. Bronicki, Chairman, Ormat Technologies, Inc., Reno, NV, USA. Advanced Power Cycles for Enhancing Geothermal Sustainability: 1000 MW Deployed Worldwide (Invited Panel Presentation Summary 08GM0355)
5. Ingólfur Hrólfsson and Sigurgeir Bjorn Geirsson, Orkuveita Reykjavikur, Reykjavík, Iceland. Geothermal Power Plants in the Hengill Area (Invited Panel Presentation Summary 08GM0618)
6. Egill Benedikt Hreinsson, University of Iceland, Reykjavik, Iceland: The Economic Rent in Hydro and Geothermal Resources in Iceland with Reference to International Energy Markets and Resource Cost Structure (Invited Panel Presentation Summary 08GM0965)
7. Nicolas Cuenot, J. P. Faucher, D. Fritsch and A. Genter, European Economic Interest Group (EEIG) Heat Mining, France and D. Szablinski, Pfalzwerke AG, Germany. The European EGS Project at Soultz-sous-Forets: from Extensive Exploration to Power Production (Invited Panel Presentation Summary 08GM1228)
8. Arni Gunnarsson, Landsvirkjun, Reykjavik, Iceland. NE-Iceland Geothermal Project: Development of 400 MWe Generation Capacity (Invited Discusser)
9. Dr. Jefferson Tester, MIT, MA, USA. Future of Geothermal Energy in USA (Invited Discusser)
10. Invited Discussers

Each Panelist will speak for approximately 20 minutes. Each presentation will be discussed immediately following the respective presentation. There will be a further opportunity for discussion of the presentations following the final presentation.

The Panel Session has been organized by Arni Gunnusson (Landsvirkjun, The National Power Company of Iceland), Reykjavik, Iceland) and Tom Hammons (Chair of International Practices for Energy Development and Power Generation IEEE, University of Glasgow, UK).

Arni Gunnusson and Tom Hammons will moderate the Panel Session.

PANELISTS

1. Guðmundur Pétursson
   Head of Karahnjukar HPP Project Management
   Landsvirkjun (National Power Company of Iceland)
   Haaleitisbraut 68
   103 Reykjavik
   Iceland
   E-mail: gp@lv.is
   Tel: +354 515 9000
   Fax: +354 515 9004

2. Björn Stefánsson
   Head of Power Projects Department
   Landsvirkjun
   Haaleitisbraut 68
   103 Reykjavik
   Iceland
   E-mail: Bjornst@lv.is
   Tel: +354 515 9252
   Fax: +354 515 9004

3. Allan Jelacic
   Acting Program Manager
   Geothermal Technologies Program
   US Department of Energy
   1000 Independence Ave. SW
   Washington, DC 10585
   USA
   E-mail: allan.jelacic@ee.doe.gov
   Tel: +1 202 586 6054
   Fax: +1 202 586 8185

   Joel L. Renner
   US Department of Energy
   1000 Independence Ave. SW
   Washington, DC 10585
   USA
   E-mail: joel.renner@hq.doe.gov (best)
   joel.renner@inl.gov
   jlrenner@q.com
   Tel: +1 202-586-6656 (office)
   +1 208-520-6010 (cell)

4. Lucien Y. Bronicki,
   Chairman
   Ormat Technologies, Inc.
   6225 Neil Road
   Reno NV 89511
   E mail: bronickily@ormat.com
   Tel: +1 775 356 9029
   Mob: + 1 775 233 9007
   Fax: 775 356-9039

5. Ingólfur Hrólfsson
   Head of New Power Projects
   Bjorn Geirsson
   Orkuveita Reykjavíkur
   Bæjarhálsi 1
   110 Reykjavík
   Iceland
   E-mail: ingolfur.Hrolfsson@or.is

sigurgeir.bjorn@or.is
Tel: +354 516 6910
Mob: +354 617 6910

6. Egill Benedikt Hreinsson
Professor of Electrical and Computer Engineering
University of Iceland
Hjardarhaga 2-6
IS-107 Reykjavik
Iceland
E-mail: egill@hi.is
Tel: +354 525 4642
Fax: +354 525 4632

7. Nicolas Cuenot
E-mail: cuenot@soultz.net
Jean-Philippe Faucher
E-mail: faucher@soultz.net
Daniel Fritsch
E-mail: fritsch@soultz.net
Albert Genter
E-mail: genter@soultz.net
European Economic Interest Group (EEIG) Heat Mining
Route de Kutzenhausen –BP 38
67250 Kutzenhausen –
France
Tel: +33 3 88 80 53 63
Fax: +33 3 88 80 53 51

Dariusz Szablinski
Pfalzwerke AG
Landauer Strasse 28
76870 Kandel
Germany
E-mail: szablinski@soultz.net
Tel: +49 7275 9555 97
Fax: +49 7275 9555 20

8. Arni Gunnarsson
Project Manager - Geothermal Power Generation
Enginering and Construction Department
Landsvirkjun (National Power Company of Iceland)
Haaleitisbraut 68
103 Reykjavik
Iceland
E-mail: Arnig@lv.is
Tel: +354-515 9171
Fax: +354 515 9004

9 Professor Jefferson W. Tester
Invited Discusser
H.P. Meissner Professor of Chemical Engineering
Chemical Engineering Department
Massachusetts Institute of Technology
77 Massachusetts Avenue, Room 66-454
Cambridge, MA 02139
USA
E-mail: TESTEREL@MIT.EDU
Tel: +1: 617-253-7090
Fax: 617-258-5042

PANEL SESSION CHAIRS

Tom Hammons
Chair International Practices for Energy Development and Power Generation
Glasgow University
11C Winton Drive
Glasgow G12 0PZ
UK
E-mail: T.Hammons@ieee.org
Tel: +44 141 339 7770

Arni Gunnusson
Project Manager - Geothermal Power Generation
Enginering and Construction Department
Landsvirkjun (National Power Company of Iceland)
Haaleitisbraut 68
103 Reykjavik
Iceland
E-mail: Arnig@lv.is
Tel: +354-515 9171
Fax: +354 515 9004

BIOGRAPHIES

Thomas James Hammons (F'96) received the degree of ACGI from City and Guilds College, London, U.K. and the B.Sc. degree in Engineering (1st Class Honors), and the DIC, and Ph.D. degrees from Imperial College, London University.

He is a member of the teaching faculty of the Faculty of Engineering, University of Glasgow, Scotland, U.K. Prior to this he was employed as an Engineer in the Systems Engineering Department of Associated Electrical Industries, Manchester, UK. He was Professor of Electrical and Computer Engineering at McMaster University,Hamilton, Ontario, Canada in 1978-1979. He was a Visiting Professor at the Silesian Polytechnic University, Poland in 1978, a Visiting Professor at the Czechoslovakian Academy of Sciences, Prague in 1982, 1985 and 1988, and a Visiting Professor at the Polytechnic University of Grenoble, France in 1984. He is the author/co-author of over 350 scientific articles and papers on electrical power engineering. He has lectured extensively in North America, Africa, Asia, and both in Eastern and Western Europe.

Dr Hammons is Chair of International Practices for Energy Development and Power Generation of IEEE, and Past Chair of United Kingdom and Republic of Ireland (UKRI) Section IEEE. He received the IEEE Power Engineering Society 2003 Outstanding Large Chapter Award as Chair of the United Kingdom and Republic of Ireland Section Power Engineering Chapter (1994~2003) in 2004; and the IEEE Power Engineering Society Energy Development and Power Generation Award in Recognition of Distinguished Service to the Committee in 1996. He also received two higher honorary Doctorates in Engineering. He is a Founder Member of the International Universities Power Engineering Conference (UPEC) (Convener 1967). He is currently Permanent Secretary of UPEC. He is a registered European Engineer in the Federation of National Engineering Associations in Europe.

Arni Gunnusson received the degree of M.Sc.in Mechanical Engineering at the Royal Institute of Technology (KTH), Stockholm, Sweden in 1973 where his main subject was. Hydraulic and pneumatic engineering. In 1975 he was awarded a M.Sc. in Energy Technology at KTH and in 1976. gained a B.Sc. degree in Business Administration at Stockholm School of Economics, Stockholm (Handelshögskolan), Sweden. Currently, since 2002, he is Project Manager with Landsvirkjun, The National Power Company of Iceland.

His experience includes Chief engineer and Project Manager of the Reykjavík District Heating Company, Managing Director and Project Manager of Orkuvirki-Gils Ltd. Reykjavik, where his main responsibilities comprised the installation of four 30-35 MWe geothermal power stations in Iceland, and Managing Director of VAG Ltd. and IGE Ltd., consulting and contracting companies in the fields of geothermal utilisation, control system and project management. From 1991-2001 he was an independent Engineering Consultant with VAG Ltd., an engineering consultant and contractor in the fields of geothermal utilisation, control engineering and project management. responsible for feasibility studies, construction, and improvements in operation of geothermal wells/reservoirs by deep well pumps, new control systems etc. for district heating and cold water schemes in Iceland. His experience abroad includes geothermal projects in China, Romania, The Slovak Republic, Turkey and Germany. Has been engaged in project negotiations in Hungary, Poland, Slovenia, Bosnia and Russia (Kamchatka). Since 1995 he has been Director, Icelandic Geothermal Engineering (IGE), an engineering consultant and contractor in the fields of geothermal utilisation, where the main activities are turn key projects in geothermal utilisation, mainly deep well pump installations. Since Project manager for the geothermal research and exploration drilling in new geothermal fields in Iceland, leased by Landsvirkjun. Since 2002, he has been Project Manager with the Landsvirkjun, Engineering and Construction Department responsible for geothermal research and exploration drilling in new geothermal fields in Iceland, leased by Landsvirkjun. He was also Project Manager in this period for Penn-stock and Gate-equipment during construction of the Kárahnjúka 700 MWe hydro power plant in NE-Iceland.

Professional Membership includes Icelandic Association of Chartered Engineers, Icelandic Society of Economists and Business Administrators, Swedish Association of Chartered Engineers, Icelandic Project Management Society, Geothermal Resources Council – GRC, International Geothermal Association-IGA, European Geothermal Energy Council-EGEC, and the Icelandic Geothermal Council-JHI.

Received 11 February 2008
Paper 08GM0646

1. The Karahnjukar 700 MWe Hydro Power Project in NE-Iceland: Challenges During Construction and the Completion Phase

Guðmundur Pétursson, Head of the Project Management, Landsvirkjun, Reykjavik, Iceland.

Abstract--The presentation explains the basic layout of the 700 MW Kárahnjúkar Hydroelectric Project being constructed in north-eastern Iceland by Landsvirkjun, the National Power Company, and near to completion now. The challenges during construction, particularly the difficulties related to the extensive underground works, the Project includes extreme long headrace and access tunnels of around 75 km. The main dam construction is also explained as well as the challenging commissioning work for the generating units and the time constraints of the project. All 6 generating units are already in operation.

Keywords-- Construction, hydro.

1. BASIC DESIGN AND PURPOSE

The main features of the 700 MW Kárahnjúkar Hydroelectric Project are the 200 m high concrete faced rock fill dam, being the highest in Europe of such kind, containing the main reservoir of 57 km^2 and the extremely long semi horizontal headrace tunnel of 40 km length in one stretch plus access and side tunnels, another 20 km. The gross head is 600 meters and two parallel vertical steel penstocks of 450 m height, among the highest in the world, conduct the water to the 6 high head Francis turbines that are equipped with high efficiency splitter blade runners. The powerhouse and transformer cavern are underground.

The very tight construction schedule over a period of 4½ years has put many constraints on the project mainly due to unforeseen geological conditions at the site.

Construction started in spring of 2003 and 5 generating units out of 6 went into full service in November last year and the last unit in January 2008.

The Power plant is primarily being constructed to supply electricity to a new Aluminum smelter being built by Alcoa of USA at a distance of approx. 50 km on the east coast. Developer and Owner of the Kárahnjúkar Power plant is Landsvirkjun, The National Power Company of Iceland.

2. CONSTRUCTION EXECUTION

Both local and international construction companies and manufacturers are carrying out the construction work under more than 30 main Contracts. Design and site supervision is performed by a number of international and Icelandic engineering organizations. The Owner executes overall project management and co-ordination of works.

3. CONSTRUCTION OF THE MAIN DAM

After diversion of the river (Jökla) in December 2003 and subsequent excavation in the river

G. Petursson is with Landsvirkjun Power, Haaleitisbraut 68, 103 Reykjavik, Iceland (e-mail: gp@lvp.is)

canyon it became apparent, that faults in the rock bed were crossing the dam foundation.

Special measures for fault treatment had to be undertaken and the massive concrete toe wall in the canyon had to be re-located and re-designed. This delayed the dam construction by many months and concreting work on the toe wall (80.000 m^3) had to be carried out throughout the winter 2004/2005 at severe winter conditions.

In spite of this delay rock filling of the dam (8,5 Mio m^3) and concreting of the water sealing face slab (approx. 100.000 m^2), could be concluded in time to allow start of reservoir water filling according to the original schedule in September of last year. This was made possible by working through all winter 2005/2006 in harsh arctic climate on concreting of the face slab and finishing it and the dam rock filling up to the required minimum height of 590 m a.s.l. prior to start of reservoir filling. The remainder of the concrete face slab was constructed after water filling had started and was finished by end of 2006. The 7 m high concrete parapet wall on the top of the dam as well as the spillway chute were completed last summer as the water level rose in the reservoir. The water level had risen to the full level of 625 m a.s.l. at the end of October 2007.

By modifying and accelerating construction procedures and sequences for the dam and related structures it was secured that the dam was completed and that the Power plant would be capable of providing full power to the important customer during coming winter and spring, until the next summer flood and glacial melt will fill the completed reservoir again next summer.

4. CONSTRUCTION OF THE HEADRACE TUNNEL

Another major obstacle along the project route was difficult geological conditions in the headrace tunnel. The main stretch of the 40 km long headrace tunnel was excavated by 3 tunnel boring machines (TBM´s) of 7,2-7,6 m diameter. All 3 encountered difficulties and were slowed down or held up significantly by heavy ingress of water (TBM3), fractured rock and loose in-fills (TBM2) and by soft sedimentary layers (TBM1).

TBM3 was first stopped prematurely due to water ingress and slow pace and was turned around to drill towards TBM2 leaving the remaining tunnel section (approx. 1 km) to be drilled and blasted the conventional way. By doing so 3-4 months were saved in construction time for the respective sections.

TBM2 got stuck twice in loose rock and fault zones with gravel infill and water ingress and was practically held up for 6-7 months, progressing only some 70 m during remedial and support works in the tunnel.

TBM1 was slowed down due to soft layers of sedimentary material in the initial phase but broke through first of the three after some 15 km of drilling on September 9th 2006. Last break through by TBM3 was on December 5th last year.

Because of these delays in tunnel excavation the finishing works inside the tunnel, i.e. rock support, surface treatment, concrete structures, cleaning out, etc. became most critical for the project completion and great efforts had to be made in order to speed up those works.

Apart from increasing the workforce up to above 700 men working inside the tunnels additional equipment was brought in. Shot Crete equipment and concrete handling equipment, additional trains and railway system, etc. Transport logistics and material handling gained crucial importance. Modified designs to allow better construct ability and acceleration of works were introduced among other things, such as incentive payments and increased working time. Drop shafts were drilled from the surface (180-200 m above tunnel) to allow more efficient transport of concrete to the tunnel. Additional access to the tunnels was also provided for by constructing a fourth adit, and by using the surge tunnel and the surge shaft for transportation of equipment and personnel to the work fronts.

By doing all of this by joint effort of Contractors, the Engineer and the Owner the delays in tunnel excavation could be mitigated considerably.

5. OTHER CONSTRUCTION WORK

In addition to the above described also other works have had to be adjusted to the actual situation and circumstances.

The underground powerhouse construction as well as manufacturing and installation of electro-mechanical equipment have basically been according to the original schedule. Some minor delays have occurred in equipment manufacturing and in installation of the pressure shaft steel linings and hydro mechanical gate equipment that, however, did not affect the start up date.

6. COMMISIONING OF THE PROJECT

In order to make start-up power available on time to the aluminum smelter it was decided to operate the first generating unit of the PowerStation without water as synchro condenser. This was made possible by installing appropriate additional electronic converter equipment for start up of unit no. 1 from the grid. The generator is de-coupled from the turbine shaft, which is lowered slightly, and a protective cover installed on top of the draft tube in place of the draft tube cone. With these arrangements for unit no. 1 the weak electrical network on the east coast is supported substantially, transmission capacity increased and voltage regulation with the generator provided for. Thus this allowed start-up of the aluminum smelter on time in April 2007 from the national grid with an initial supply of up to 100 MW. The two 220 kV transmission lines between power plant and smelter with a link to the existing 132 kV national grid were commissioned in January/February 2007.

The testing and commissioning period for the remaining generating units was then to be shortened and accelerated considerably in order to compensate for the delay in tunnel works and water availability. Two and two generating units were to be commissioned simultaneously on separate pressure shaft penstocks. This of course called for precise planning and additional commissioning resources. Due to further difficulties and delays in completing the headrace tunnel, however, the generating units no. 2-6 have been operationally tested with water and commissioned up to synchronization and part load operation at much reduced head water pressure and flow (450 m instead of 600 m water column). The reason for this being, that it was possible to complete the lowest third (15 km) of the semi-horizontal headrace tunnel earlier (end of July) and so enable water filling of that section considerably ahead of the remaining tunnel sections.

This has saved 2-3 weeks of testing time for each of the generating units that can now be brought on the line and operated at full power within one week each after availability of full head and flow. This methodology has brought about a substantial advancement of full power production from the Kárahnjúkar plant.

The filling of the lowest third of the headrace tunnel was effected by inflow of leakage water into the tunnel and pumping, to fill that tunnel section as well as both vertical pressure shaft penstocks. Filling of the remaining part started on October 13th 2007 and was completed on November 1st.

In spite of the severe delays in tunnel completion the project went into full power operation at the end of 2007, close to the original plans (October 2007), and all work shall be completed by end of 2008.

The main bulk of work left for this year is in a second catchment and diversion area (Jökulsárveita/Hraunaveita), connected to the main headrace tunnel through a 10 km long and 7,2 m wide side tunnel presently being drilled by a TBM. Further tunnels and two smaller earth fill dams are also being constructed in that area.

7. GENERAL REMARKS

The Project has been faced with considerable resistance and criticism by diverse opponents and environmentalists, both local and international, and has had to fight against this throughout the project period. Several protest actions have been arranged on site and elsewhere during the construction phase, but this has now calmed down.

The construction workers and the project personnel have performed outstandingly under toughest environmental conditions at the site, rough weathers, dangerous working areas and remote location away from the families and deserve recognition for their great efforts.

8. REFERENCES

[1] Numerous Project Documentation of Landsvirkjun.

[2] B. Khalighi, G. Porta, G. Giacomin, M. Franceschi, "Breaking the ice" *International Waterpower and Dam construction,* Nov. 2005.

[3] G. Pétursson, “Kárahnjúkar 700 MW Hydroelectric Project” *European Sustainable Energy Review,* Issue 1, 2007.

[4] Kárahnjúkar and Landsvirkjun websites: www.lv.is, www.karahnjukar.is

9. BIOGRAPHIES

Gudmundur Petursson graduated with M.Sc. Dipl.Ing. Degree in electrical engineering from the Technical University of Darmstadt, Germany in 1973. He has over 35 years of experience in the hydropower industry, working for ABB (Brown Boveri & Cie Mannheim, Germany), MWH (Harza Engineering Company, Chicago) and Landsvirkjun, the National Power Company of Iceland. Over the years he has worked on project administration and as a resident engineer for hydropower projects in Germany, Iran, Venezuela and Iceland. He is currently the Head of the Project Management for the $1.5-billion 700 MW Karahnjukar hydroelectric project in eastern Iceland. Mr. Petursson’s areas of expertise include project management, design, tender specifications, contracting, and supervision of design, manufacturing, erection and testing of electro-mechanical equipment and civil structures for power generation projects. He is an active member of the Icelandic Association of Chartered Engineers and an honorary member of the Project Management Association of Iceland where he has been responsible for certification of Icelandic project managers for the International Project Management Association.

Received 18 February 2008
Paper 08GM1207

2. Iceland Deep Drilling Project, Exploration of Deep Unconventional Geothermal Resources

Björn Stefánsson, Head of Power Projects Department, Bjarni Pálsson, and Guðmundur Ómar Friðleifsson, Landsvirkjun, Reykjavik, Iceland.

Abstract-- The Iceland Deep Drilling Project (IDDP) is a long-term research and development program aimed to improve the efficiency and economics of geothermal power generation by harnessing deep natural supercritical hydrous fluids obtained at drillable depths. Producing supercritical fluids will require drilling wells and sampling fluids and rocks to depths of 3.5 to 5 km, and at temperatures of 450-600°C. The current plan is to drill and test a series of such deep boreholes in Iceland; at the Krafla, the Hengill, and the Reykjanes high temperature geothermal fields. Investigations have indicated that the hydrothermal system extends beyond the three already developed target zones, to depths where temperatures should exceed 550-650°C. Occurrence of frequent seismic activity below 5 km indicates brittle and permeable rocks. A deep well producing 0.67 m^3/sec steam (~2400 m^3/h) from a reservoir with a temperature significantly above 450°C could yield enough high-enthalpy steam to generate 40-50 MW of electric power. This exceeds by an order of magnitude the power typically obtained from conventional geothermal wells. Being able to harness such unconventional geothermal resources is of great importance for many areas in the world where green sustainable energy is needed.

Keywords: Geothermal energy, natural supercritical systems, technological innovation.

1. INTRODUCTION

The main use of geothermal energy in Iceland is for space heating and almost 90% of all houses are heated by this energy source. Other sectors of direct use are swimming pools, snow melting, industry, greenhouses and fish farming. Expansion in the energy intensive industry in recent years has led to rapid increase in electricity demand in the country. This has stimulated the development of geothermal power production and resulted in new plants as well as extension of existing plants. At the end of 2007, the total installed capacity of geothermal power plants in the country is 422 MWe. Some 600-700 MWe are currently under development.

The Iceland Deep Drilling Project was initiated in the year 2000 by an Icelandic energy consortium, consisting of Hitaveita Sudurnesja Ltd. (HS), Landsvirkjun (LV), Orkuveita Reykjavikur (OR) and the Icelandic National Energy Authority (Orkustofnun (OS)). In 2007, Alcoa Inc. joined the IDDP consortium. The principal aim of the IDDP is to enhance the economics of high temperature geothermal resources by producing from deep reservoirs at supercritical conditions. The project has generated widespread international interest and the establishment of an international Sciences Application Group of Advisors (SAGA). To date, six international workshops have been held in Iceland, and a central science team established with participation from Iceland, USA, Japan, New Zealand, Italy, Germany and France. Some 40-50-research proposals and 100-150 scientists and their students are currently active in the project.

A feasibility study on the IDDP concept was concluded in 2003, available at the IDDP website: http://www.iddp.is/.

Over the next few years, IDDP plans to drill a series of boreholes to penetrate into supercritical fluids believed to be present beneath three currently exploited geothermal systems in Iceland (Figure 1). This requires drilling down to 4 to 5 km, and sampling hydrothermal fluids at temperatures of 450 to 600°C. The physics and chemistry of natural supercritical geothermal fluids in the Earth's crust are of great interest, while hitherto no attempts have been made to put such natural supercritical fluids to practical use. Studies of the supercritical phenomena have been restricted to either small-scale laboratory experiments or to investigations of “fossil” supercritical systems exposed in mines and outcrops. The IDDP will drill deep enough into already known geothermal reservoirs in Iceland to reach supercritical conditions believed to exist at depths. Iceland is a particularly favorable location for research on supercritical fluids, as seismic and volcanic activities in an environment of active rifting will create both high permeability and high temperatures at drillable depths.

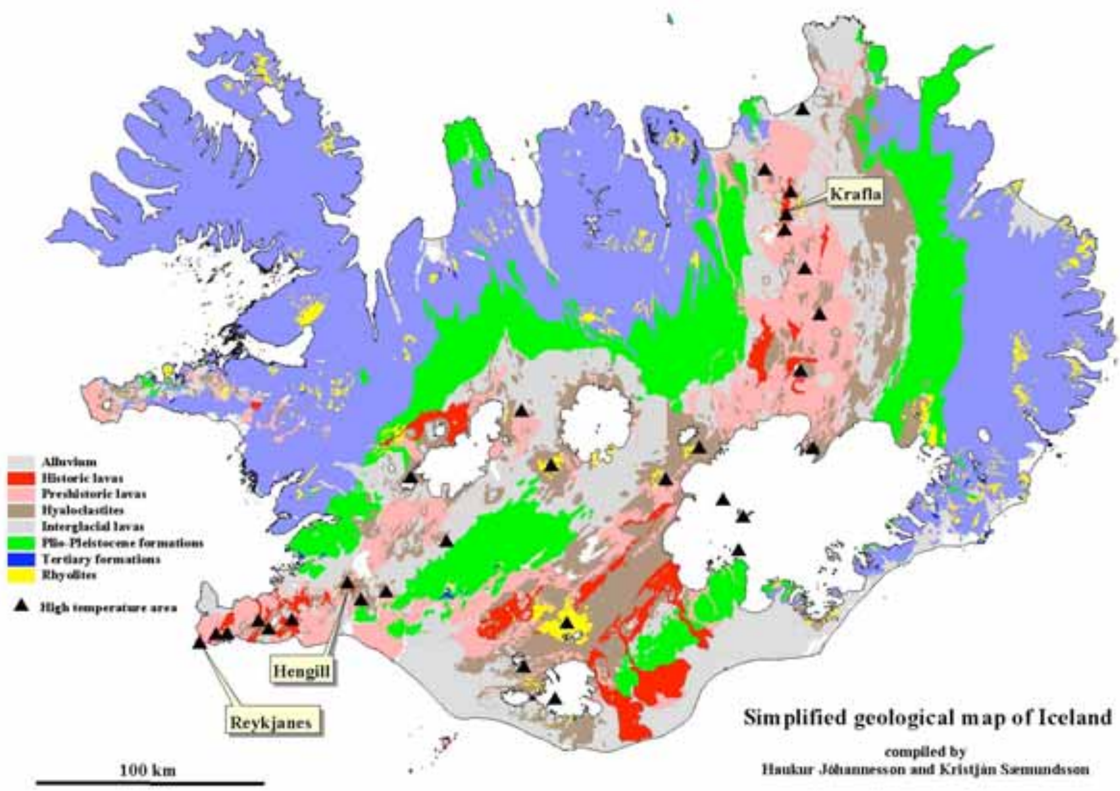


Fig. 1. A geological map of Iceland showing the location of the three high-temperature hydrothermal systems selected as sites for deep boreholes by the IDDP.

2. SUPERCRITICAL GEOTHERMAL FLUIDS

Large changes in physical properties of fluids occur near the critical point in dilute systems. Orders of magnitude increases in the ratio of buoyancy forces to viscous forces occur that can lead to extremely high rates of mass and energy transport. Similarly, because of major changes in the solubility of minerals above and below the critical state, supercritical phenomena can play a major role in high temperature water/rock reaction and the transport of dissolved metals.

At temperatures and pressures above the critical point, which for pure water is at 221 bars and 374°C, only a single-phase supercritical fluid exists. Figure 2 shows the pressure-enthalpy diagram for pure water, showing selected isotherms. Steam turbines in geothermal plants generate electricity by condensing the steam separated from the two phase field (liquid and steam field in Figure 2) which, depending upon the enthalpy and pressure at which steam separation occurs, is often only 20-30% of the total mass flow. The concept behind the Deep Drilling program is to bring supercritical fluid to the surface in such a way that it transitions directly to superheated steam along a path like F-G in Figure 2, resulting in a much greater power output than from a typical geothermal well.

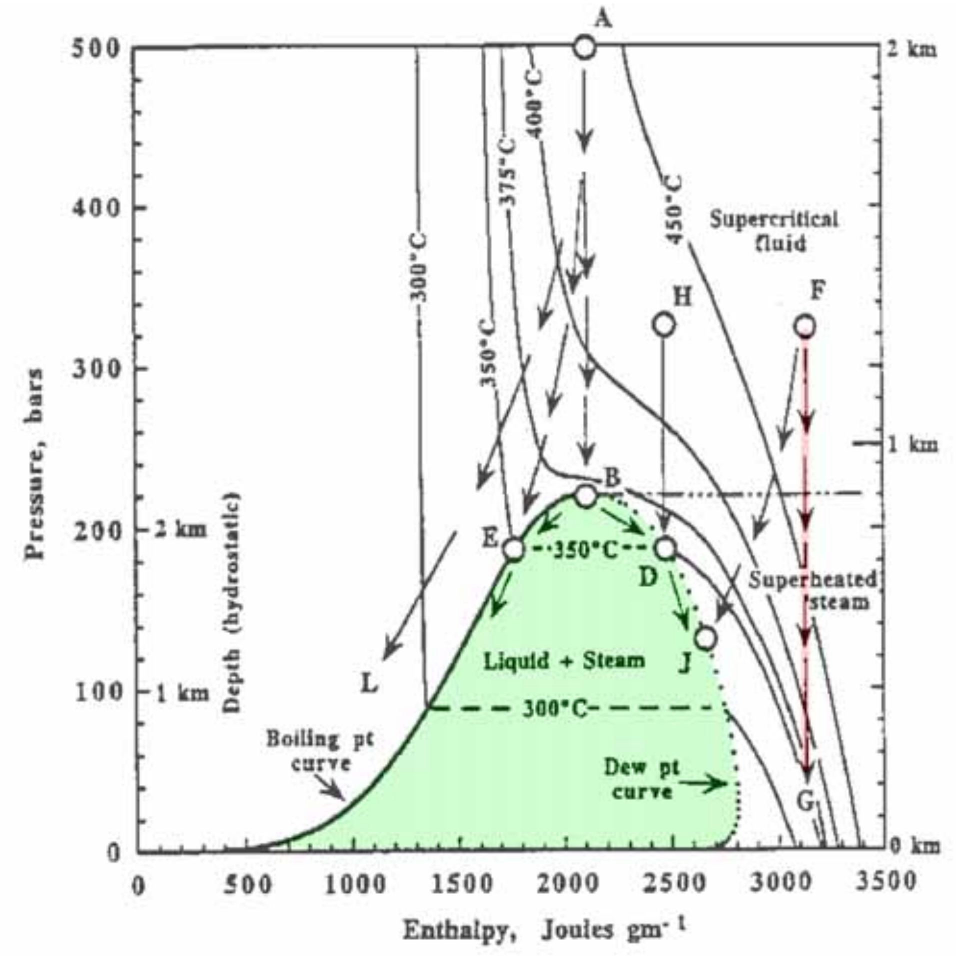


Fig. 2. Pressure enthalpy diagram for pure H_2O with selected isotherms. The conditions under which steam and water coexist is shown by the shaded area, bounded by the boiling point curve to the left and the dew point curve to the right. The arrows show different possible cooling paths (from Fournier, 1999).

Supercritical conditions have been encountered during drilling in a small number of geothermal fields, like in Larderello in Italy, Kakkonda in Japan, and at Nesjavellir in Iceland, where they have presented problems for commercial exploitation and were sealed off from the conventional part of the systems. Apart from the high P-T conditions where underground blowout was involved, like at Nesjavellir (Steingrimsson et al., 1990), the problems include low permeability, hole instability due to thermal creep, and the presence of acid volcanic gases. However, the drilling technology used in these cases was not designed to handle the conditions encountered when supercritical hydrous fluids were unexpectedly penetrated.

The Iceland Deep Drilling Project intends to meet the hostile conditions expected in supercritical geothermal reservoirs by a conservative well design and by adopting the necessary safety measures. The safety casing will be cemented down to 2.4 km before drilling down to 3.5 km depth or deeper to reach the critical point. Once beyond that, the production casing will be cemented in order to produce only the supercritical fluid. By releasing the pressure, the supercritical fluid will expand and move upwards to the surface through the well bore as a superheated dry steam, following a path like F-G in Figure 2. The deep casings will prevent the fluid from mixing with the two-phase zone and as the pressure decreases, condensation is less likely to occur. A pilot study for harnessing the fluid will need to be undertaken, especially with respect to the fluid chemistry that will only be known after drilling. Albertson et al (2003 a, b) in the IDDP feasibility study assumed that the superheated steam would be brought into a heat exchanger with a clean water circuit and then re-injected into the ground. Despite the heat loss, an order of magnitude increase in power output as compared to conventional high-temperature wells would be realized by utilizing such a fluid, assuming the same volumetric inflow rate of steam in both cases.

3. DRILLING IN IDDP WELLS

3.1 Design

Conventional geothermal drilling technique will be used in drilling the IDDP wells. In order to meet the major goals, set by the project sponsors, the first well was designed as a dual-purpose hole. Firstly, to meet the engineering goals of the power companies, it is designed as an exploration/production well, and secondly, to meet the scientific goals of understanding the supercritical environment, some spot cores will be taken in the lowest part of the drill hole, which hopefully will be the supercritical zone.

As for the well design, the top part of the anchor casing has to be of special creep resistant steel, but conventional soft API grade K-55 can be used for other casing strings. The well casing has to withstand extreme temperatures and pressures and the safety aspects received a special attention in the design process. The greatest danger to the casing is thermal cycling, as the steel is stressed beyond the yield point due to limited thermal expansion. The greatest strain on the casing is due to expansion during heating and cooling of the string. The highest strain is expected when the casing string is cooled from flowing conditions to 20°C, e.g. in case of work-over operations, side tracking, deepening or injection testing.

The depth of each casing string was determined, based on expected pressures in a flowing two-phase well, in such a manner as to be able to control underground blow-out conditions with heavy mud of 1.4 g/cm^3 density. Underground blowout condition means that an internal flow occurs within the well bore from a deep feed zone (fracture) to a shallower feed zone in the hole where the reservoir pressure is lower. Such conditions, for instance, were met in one well of the Hengill drill fields in 1985, involving flowing supercritical or superheated fluid (>380°C hot) from a deep feed zone at 2.2 km depth up to a shallower feed zone at 1.1 km depth (Steingrimsson et al. 1990). The casing design of the IDDP wells aims at meeting such conditions at all depths and also, if necessary, to flow test at such conditions.

Recognizing when supercritical conditions are reached during drilling will best be done by studying mineral assemblages and fluid inclusions in cores or cuttings. Nevertheless, in the event of total loss of circulation in the deeper part of the well, it may be possible to use special down-hole logging tools rated up to 300°C, by sufficient cooling of the well down to the feed point. The 6th Framework Program of the European Commission is currently supporting a down-hole tool-developing project, called HITI, for meeting such conditions. However, when down-hole logging is not possible and there is a loss of circulation and no return of drill cuttings in the supercritical zone, the only alternative is to obtain drill cores from the zones of greatest interest.

The IDDP recognized that a thorough understanding of geothermal reservoirs at supercritical conditions in natural settings is a difficult assignment. Accordingly, from the very onset, IDDP has welcomed international participation in the project for sharing both the science and the funding, for the mutual benefits of all concerned. The drilling of the first IDDP well is planned to commence in August of 2008.

3.2 Potential Drill Sites

Geothermal reservoirs at supercritical conditions are potentially to be found worldwide in any active volcanic complex. However, the depth to such reservoirs may vary greatly from shallow to deep, and the simplest approach would surely be to seek supercritical reservoirs in active high-temperature geothermal fields, closest to the earth's surface, in both sub aerial and submarine settings. Each high temperature hydrothermal system requires site-specific attention to target drill sites for reaching DUGR reservoirs with supercritical conditions and permeable rocks at drillable depths.

Figure 3 shows a simplified model of a possible geologic environment and utilization concept. The depth of production casing is of paramount importance for successful exploitation to avoid mixing supercritical with sub critical fluids, as explained in section 2 above.

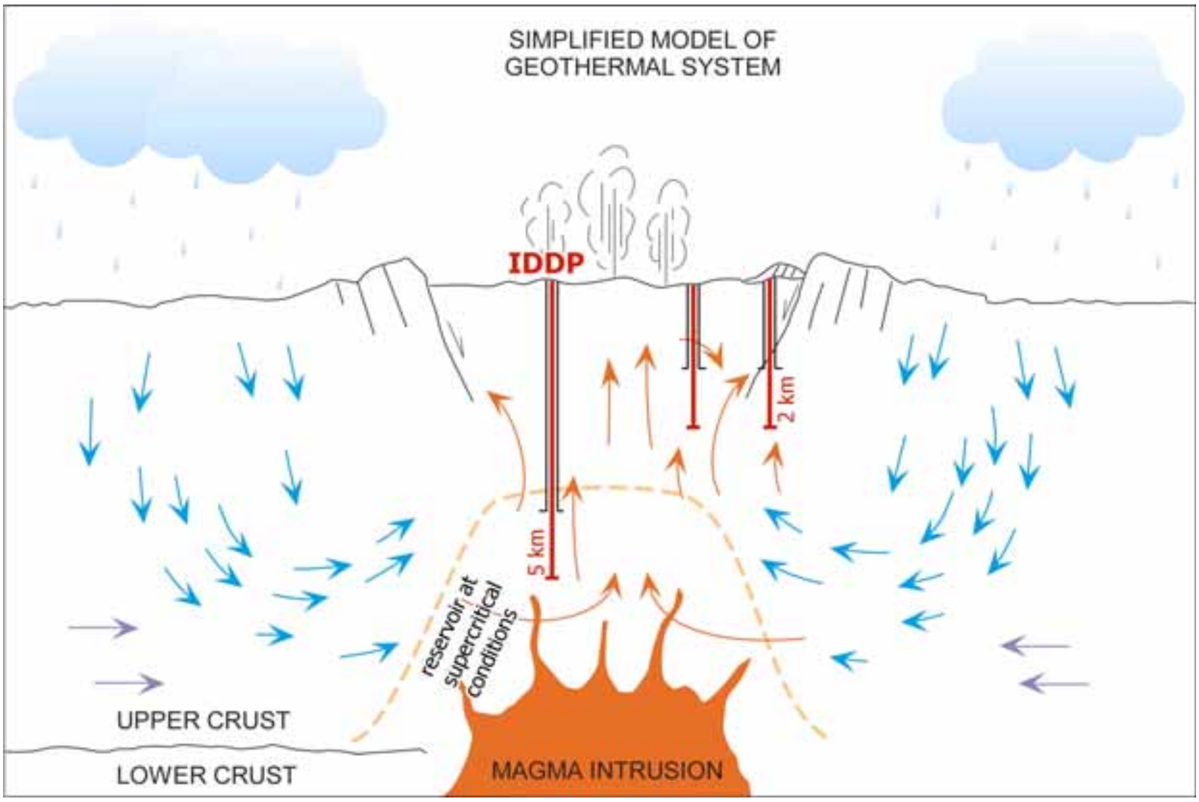


Fig. 3. A simplified geothermal model showing schematically a reservoir at supercritical conditions surrounding a magma tic heat source. It is of vital importance that the IDDP production casing reaches down into the supercritical reservoir.

While all active volcanic complexes are potential targets for finding deep geothermal systems at supercritical conditions, these volcanic complexes are of different ages and at different stages in their evolution; some are at infancy, others are mature and some are close to extinction. The simple sequence of the evolution of volcanic complexes observed in Iceland is useful to illustrate this concept. They evolve from infancy inside an active segment within the volcanic rift zones that cross the Iceland, mature into evolved central volcanoes, with magma chambers or accumulation of magma tic intrusions at shallow depths, and, eventually drift out of the active rift zones, cooling down as replenishment of magma stops, and become a subject for uplift and erosion. Altogether about one hundred such volcanic complexes are exposed within Iceland, while only about a third of them are presently active. Most commonly, high temperature geothermal systems accompany these volcanic complexes, and all these geothermal systems ripen to maturity and onwards to extinction. The lifecycle of a typical Icelandic volcanic center is about 1 ma and the lifetime of a typical high-temperature geothermal system is about a third of that time. Due to heavy erosion during glacial episodes, some of the old volcanic complexes were eroded to their roots, down to 2-3 km depth. In SE-Iceland for example, the former magma chambers now are exposed as intrusive complexes. Studies of such complexes show clear evidence of interaction between the magma tic heat sources and the hydrothermal systems, involving supercritical conditions (e.g. Fridleifsson 1984). This is a style of volcanic evolution exemplary of the world-encircling mid-ocean ridges, where submarine hot springs (black smokers) are fueled by supercritical reservoirs at depth.

The three Icelandic fields deemed to be prime targets for DUGR exploration, the Reykjanes, Hengill and Krafla geothermal systems (Fig. 1), demonstrate different stages in the evolution of their magma-hydrothermal evolution, the first being at infancy, the second being “middle aged” and the third being mature. Accordingly, deep drilling at all three will permit studying different stages in the development of supercritical conditions at depth. Additionally, they exhibit different fluid compositions, the first involving modified seawater, but the other two dilute fluids of meteoric origin. Extensive production drilling in all three-drill fields has guided us to the hottest parts of the hydrothermal up-flow zones. However, the nature of their heat sources is somewhat poorly known, except in the mature case of the Krafla system, where a magma chamber has been identified at only 3-4 km depth. (e.g. Einarsson, 1978, Einarsson and Brandsdottir, 2006).

4. POTENTIAL BENEFITS

4.1 Power Generation

The high-temperature fluids expected from the IDDP wells offer two advantages over fluids from conventional wells for generation of electric power, (i) higher enthalpy, which promises high power output per unit mass, and (ii) higher pressure which keeps the fluid density high and thus contributes to a high mass-flow rate.

Albertsson et al. (2003 a, b) have estimated the electric power output that can be expected from an IDDP well compared with that from a conventional geothermal well. For comparison a conventional well was considered to be producing dry steam with a volumetric rate of inflow to the well of 0.67 m^3/s (~2400 m^3/h) at a wellhead pressure of 25 bar_a and a down hole pressure of 30 $bar_{a.}$ This would yield steam at a rate capable of generating about 5 MWe. On the other hand a well tapping a supercritical reservoir with temperatures of 430–550°C and pressures of 230-260 bar may be expected to yield 50 MWe given the same volumetric inflow rate of 0.67 m^3/s. Thus, if similar conditions apply, a supercritical well could yield an order of magnitude improvement in power output compared to a typical conventional well.

The choice of technology to be applied for the power generation cannot be decided until the physical and chemical properties of the fluid are determined. Nonetheless, it appears likely that the fluid will be used indirectly, in a heat exchange circuit of some kind. In such a process the fluid from the well would be cooled and condensed in a heat exchanger and then injected back into the field. This heat exchanger would act as an evaporator in a conventional closed power-generating cycle.

4.2 Scientific Studies

In addition to investigations and sampling of fluids at supercritical conditions the IDDP will permit scientific studies of a broad range of important geological issues, such as investigation of the development of a large igneous province, and the nature of magma-hydrothermal fluid circulation on the landward extension of the Mid-Atlantic Ridge in Iceland. In addition, the IDDP will require use of techniques for high-temperature drilling, well completion, logging, and sampling, techniques that will have a potential for widespread applications in drilling into oceanic and continental high-temperature hydrothermal systems. The prospect opens up the opportunity for a very comprehensive scientific program investigating the anatomy of a mid-ocean rift system, by tying together land–based and ocean-based deep borehole studies with complementary geological and geophysical and seismic imaging studies, putting the drilling activities into a broader regional geologic context.

The addition of a scientific program to the industry driven IDDP drilling venture has obvious mutual advantages. The IDDP provides opportunities for scientists to become involved in an ambitious project that has a budget larger than can be funded by the usual agencies that fund scientific drilling on land. In turn, the industrial partners will benefit from strong scientific contributions that will expand opportunities for innovation and provide a perspective that can be of critical importance in the context of poorly understood natural systems such as supercritical geothermal reservoirs.

4.3 Economic Benefits

The potential economic benefits of the IDDP project may be listed as follows:

1. Increased power output per well, perhaps by an order of magnitude, and production of higher-value, high-pressure, high-temperature steam.
2. Development of an environmentally benign, high-enthalpy energy source beneath currently producing geothermal fields.
3. Extended lifetime of the exploited geothermal reservoirs and power generation facilities.
4. Re-evaluation of the geothermal resource base.
5. Industrial, educational, and economic spin-off.
6. Knowledge of permeability within drill fields deeper than 2-3 km depth.
7. Knowledge of heat transfer from magma to water.
8. Heat sweeping by injection of water into hot, deep wells.
9. Possible extraction of valuable chemical products.
10. Advances in research on ocean floor hydrothermal systems (the Reykjanes field).

Amongst approaches to improve the economics of the geothermal industry, three are fairly obvious: (i) to reduce the cost of drilling and completing geothermal production wells as possible, (ii) to cascade the usage of thermal energy by using the effluent water for domestic heating and for industrial processes, and (iii) to reduce the number of wells needed by increasing the power output of each well, by producing supercritical fluids. Accordingly, the completion of the IDDP project is of considerable importance for the geothermal industry at large.

4.4 Environmental Issues

Developing environmentally benign high-enthalpy energy sources below the depth of currently producing geothermal fields is not only of economic value in relation to the already installed infrastructures, but it is also of environmental value by diminishing the environmental impact geothermal utilization. Producing more power without increasing the “foot print” of the exploited drill field is an obvious benefit. Most high temperature geothermal surface manifestations occur within some sort of active volcanic settings, and many such fields around the world are preserved as national parks. If the production of supercritical reservoirs through deep holes proves more economic than production of the conventional upper parts of the geothermal systems, it would be economically feasible to use deep directional drilling similar to that becoming common in the oil industry. This could revolutionize the approaches available for developing high enthalpy geothermal resources underneath environmentally sensitive areas.

5. POTENTIAL IMPACTS

5.1 Global Impacts

A successful outcome of the IDDP project could lead to a major step forward in using high temperature geothermal energy on a global scale. Increased use of such a sustainable source of non-polluting energy sources would help to counterbalance the threat of global warming by due to the release of greenhouse gases from the use of hydrocarbon fuels. The potential impact of utilizing geothermal resources at supercritical conditions could become quite significant. Not only would this call for re-evaluation of the geothermal energy resource base on a local scale, but also on a global scale. If producing supercritical fluids became widespread it would lead to a major enlargement of the accessible geothermal resource base.

High temperature geothermal resources are located at most plate boundaries around the globe, mostly above the subduction zones (convergent plate boundaries), where oceanic plates creep under continental crust (like on the so-called Circum Pacific ring of fire), or at constructive plate boundaries were new crust is created like along the mid-ocean ridges (including Iceland), the African rift valley and elsewhere. Potential impact on a global scale, if deep unconventional geothermal resources (DUGR) systems can be harnessed, would undoubtedly involve many of the Circum Pacific geothermal systems. Many of those systems, like in Central America, are already within national parks and as such will be difficult or impossible to access, except by directional drilling from outside the parks. Improved economics in geothermal utilization might make extensive directional drilling feasible, like in the sea floor oil industry.

Some of the potential DUGR systems are on remote oceanic islands, like on the Aleutian island arc in the Pacific Ocean, the Azores in the Atlantic Ocean, and elsewhere, far away from the larger energy markets. Improved economics by harnessing DUGR systems at such remote locations, and improved economics in the conversion of thermal energy into potable energy carriers, like hydrogen or synthetic diesel or alike, might justify the harnessing of such remote DUGR systems.

Finally, it is conceivable that, in the more distant future, utilization of ocean floor geothermal systems might become viable. Submarine geothermal systems are abundant along the world's mid-ocean ridge systems and some of them (the black smokers) expel ~400°C hot seawater direct into the deep oceans, and precipitate chimneys of sulfide-ore deposits. The pressure of 2.5-3 km deep seawater results in supercritical hydrostatic pressures, and allows almost supercritical fluids to be expelled directly into the oceans. Tapping energy through shallow drill holes on the mid-ocean ridges using techniques initially developed by the international IDDP program is an exciting prospect.

5.2 Local Impact

In a report issued by the Icelandic Minister of Industry in 1994, the total geothermal energy accessible in the active high temperature systems in Iceland was estimated as potentially capable of yielding some 3,500 MW electric. This is only indicative of the size of the conventional accessible geothermal resource base in Iceland, without considering the possible impact of harnessing deep geothermal resources at supercritical conditions. If the power output from a single well were to be increased by an order of magnitude, what would be the total increase in power output from a developed geothermal system? Can we double or triple the production, or more? Obviously, any increase would have a positive impact on the sustainable energy budget of an environmentally benign energy source.

5.3 Potential Impact on Greenhouse Gases

In the Stern Review to the British Government 2006 (www.sternreview.org.uk) it is reported that since industrialization, greenhouse gas (GHG) levels have risen from 280 ppm CO_2 equivalent (CO_2e) to 430 ppm CO_2e today, and they increase by 2 ppm each year. The risks of the worst impacts of climate change can be substantially reduced, according to the review, if the GHG levels can be stabilized between 450 and 550 ppm CO_2e. Stabilization in this range would require emissions to be at least 25% below current levels by 2050, and perhaps much more. According to the Review, three measures need be taken, (1) taxation on GHG emission, (2) new techniques, and (3) removal of hindrances against economic energy usage. According to the Stern Report the main sources of the polluting greenhouse gases are 24% in the Power Sector, 14% in the Industry sector, another 14% in the Transport sector, and 5% in other energy related activities, altogether some 57%. Attempting to decrease CO_2e emission in any of these sectors would be a logical step to respond to the Stern Review.

The World Energy Council (WEC) has presented several scenarios for meeting the future energy requirements with varying emphasis on economic growth rates, technological progress, environmental protection and international equity (Nakicenovic et al., 1998). In all WEC´s scenarios, the peak of the fossil fuel era has already passed (Nakicenovic et al., 1998). Oil and gas are expected to continue to be important sources of energy in all cases, but the role of renewable energy sources and nuclear energy vary highly in the scenarios and the level to which these energy sources replace coal. In all the scenarios, the renewables are expected to become very significant contributors to the world primary energy consumption, providing 20-40% of the primary energy in 2050 and 30-80% in 2100. They are expected to cover a large part of the increase in the energy consumption and to replace coal.

Table 1 shows the technical potential of renewable energy resources (WEA, 2000). The technical potential is the yearly availability of the renewable resources. These estimates suggest that the technical potential of the renewables is sufficiently large to meet future world energy requirements. It is worth noting that the present annual consumption of primary energy in the world is about 400 EJ.

TABLE I

TECHNICAL POTENTIAL OF RENEWABLE ENERGY SOURCES IN EXAJOULES/A
SOURCE: WORLD ENERGY ASSESSMENT (WEA, 2000)

	EJ per year
Hydropower	50
Biomass	276
Solar energy	1575
Wind energy	640
Geothermal energy	5000
TOTAL	7600

Evidently, a large opportunity to cut the GHG emission exists with the geothermal energy sector. However this estimate did not include innovations such as IDDP.

6. CONCLUSION

The long-term program to improve the efficiency and economics of geothermal energy by harnessing deep unconventional geothermal resources in Iceland is an ambitious project to produce electricity from natural supercritical hydrous fluids from drillable depths. Producing higher-temperature fluids for generation of electric power offers two advantages over using the fluids from conventional wells: (i) higher enthalpy, which promises high power output and higher efficiency per unit mass, and (ii) higher pressure, which keeps the fluid density high and thus contributes to a higher mass-flow rates. Modeling indicates that IDDP wells could yield an order of magnitude improvement in power output compared to typical conventional wells. The choice of technology to be applied for the power generation from these high-temperature fluids will be decided after determining the physical and chemical properties of the fluids that are produced. The IDDP has plans to apply for funds to the 7th Framework Program of the European Commission for the development and prototype pilot study needed prior to production testing of the natural supercritical fluids.

There are three obvious approaches to improve the economics of the geothermal industry worldwide: (i) Cascading the usage of geothermal energy by using the effluent water from electricity production for industrial processes and for domestic heating, (ii) Reducing the cost of drilling and completing geothermal production wells, and (iii) to reduce the number of wells needed by increasing the power output of each well. The best way to achieve the latter is to produce supercritical fluids. Accordingly, the successful completion of the IDDP project is of considerable importance for the geothermal industry at large. A successful outcome would be a major step forward for the geothermal industry on a global scale, which in turn, could help to counterbalance the threat of global warming by increased use of the sustainable, non-polluting energy resources.

7. ACKNOWLEDGEMENTS

We like to acknowledge the IDDP consortium for encouraging the publication of this paper. We would also like to thank Professor Wilfred A. Elders, from the University of California, Riverside, USA, for all his efforts in serving as one of the principal investigators in the IDDP science team from the beginning.

8. REFERENCES

[1] Albertsson, A., Bjarnason, J.Ö., Gunnarsson, T., Ballzus C. and Ingason, K., 2003 a. Part III: Fluid Handling and Evaluation, 33 p. In: Iceland Deep Drilling Project, Feasibility Report, ed. G.O.Fridleifsson. *Orkustofnun Report OS-2003-007*.

[2] Albertson, A., Bjarnason, J.Ö, Gunnarsson, T., Ballzus, C. and Ingason, K., 2003 b. The Iceland Deep Drilling Project: Fluid Handling, Evaluation, and Utilization. *Proceedings of the International Geothermal Conference* IGC-2003 Reykjavik, September 2003, Session 6, pp. 23-30.

[3] Einarsson, P., 1978. S-wave shadows in the Krafla caldera in NE-Iceland, evidence for a magma chamber in the crust. *Bulletin Volcanology 41*, pp 1-9.

[4] Einarsson, P. and Brandsdottor, B., 2006. The Krafla Magma tic and Tectonic Episode of 1974-1989 at the Divergent Plate Boundary in North Iceland. . *Eos Trans.AGU 87 (52)* Fall Meet. Suppl., Abstract T33E-07.

[5] Elders, W. A., Fridleifsson, G.O., Saito. S. (2003). The Iceland Deep Drilling Project: Its Global Significance. *Proceedings of the International Geothermal Conference* IGC-2003 Reykjavik, September 2003, Session 6, pp. 1-7.

[6] Fournier, R. 1999. Hydrothermal Processes Related to Moment of Fluid Flow From Plastic into Brittle Rock in the Epithermal-Epithermal Environment. *Economic Geology*, Vol 94, no 8, pp 1193-1211.

[7] Fridleifsson, G.O., 1984. Mineralogical Evolution of a Hydrothermal System: II: Heat Sources - Fluid Interactions. *Geothermal Resources Council Transactions*, 8, pp. 119-123.

[8] Nakicenovic, N., Grübler, A., and McDonald, A. (editors), 1998: *Global Energy Perspectives*. Cambridge Univ. Press, 299 pp.

[9] Steingrímsson, B., Guðmundsson, Á., Franzson, H. and Gunnlaugsson, E. (1990). Evidence of a supercritical fluid at depth in the Nesjavellir field. *Proc. Fifteenth Workshop on Geothermal Reservoir Engineering Stanford University*, Stanford California, January 23-25, 1990 SGP-TR-130, 81-88.

[10] Stern Review, 2006: Stern Review on the Economics of Climate Change presented in October 2006, *Cambridge University Press*, www.cambridge.org/9780521700801.

[11] WEA, 2000: *World Energy Assessment: energy and the challenge of sustainability*. Prepared by UNDP, UN-DESA and the World Energy Council. United Nations Development Programme, New York, 508 pp.

[12] WEA, 2004: World Energy Assessment: overview 2004 Update. Prepared by UNDP, UN-DESA and the World Energy Council**.** *United Nations Development Programme*, New York, 85 pp.

BIOGRAPHIES

Björn Stefansson graduated in Civil Engineering, option Structural Engineering, from the Technical University of Darmstadt, Germany in 1974 and in Geotechnical Engineering from the University of California, Berkeley in 1981. He worked as a consulting engineer for Almenna Consulting Engineers in Iceland in 1974-1979 and in 1983-2000, notably in the field of hydropower developments and various other civil projects, and for Parsons Brinckerhoff Quade & Douglas Inc. in New York City USA in 1981-1983 on some tunneling works. In 2000, he joined Landsvirkjun as Head of Power Projects Department. Since 2008, he is with Landsvirkjun Power Ltd. as Managing Director of Engineering. He is a member of ASCE.

Bjarni Pálsson, graduated in mechanical and industrial engineering from the University of Iceland in 1996 and with MSc and PhD in petroleum from the Heriot-Watt University in Edinburgh in 1998 & 2004. Since 2002 he has been project manager for geothermal exploration drilling at the engineering & construction division of Landsvirkjun and since 2008 with the engineering division of Landsvirkjun Power Ltd. Since 2002 he has been in the drilling technical group of the IDDP and is currently project manager for the drilling of the IDDP well in Krafla field.

Gudmundur Omar Fridleifsson, is a geologist, received BSc-ord. & hon. from the University of Iceland 1975 & 1976, and
PhD from the University of Edinburgh 1983. Since 1975 he worked as a geothermal geologist, focusing on hydrothermal mineralogy, volcano logy and structural geology of geothermal systems, at Orkustofnun (the National Energy Authority of Iceland), and moved with its GeoScience Division to ISOR (Iceland GeoSurvey) in 2003. Since November 2007 he took up a post as the Chief Geologist at the Hitaveita Sudurnesja Ltd., the geothermal energy company that holds the permits at the Reykjanes Peninsula in Iceland. Since 2000 he has acted as a project manager for the IDDP and a principal investigator, and co-ordinates the IDDP industrial and scientific activity.

Received 14 February 2008
Paper 08GM1654

3. A Perspective on the Future of Geothermal Energy in the United States

Allan Jelacic, Acting Program Manager, Geothermal Technologies Program, US Department of Energy, Washington, DC, USA
Joel L. Renner, Idaho National Laboratory, US Department of Energy, USA

Abstract--Electricity has been produced from geothermal energy since 1960. Hydrothermal resources, naturally occurring hot water, are the fluid providers. Since these resources seem limited geothermal developers are now looking at the much larger potential resource represented by hot rocks with low productivity. This resource originally termed “hot dry rock” (HDR) but now termed “enhanced geothermal systems” (EGS) which includes the transition between hydrothermal systems and HDR will be the future for geothermal development throughout the world.
Index Terms— Geothermal energy, geothermal power generation.

1. CURRENT DEVELOPMENT

Geothermal energy has been utilized for the commercial generation of electricity in the United States since 1960. Production began at The Geysers geothermal field about 90 miles north of San Francisco, California at what is now the world’s largest geothermal field. The United States continues to be the world leader in online capacity of geothermal energy and the generation of electric power from geothermal energy. According to U. S. Energy Information Agency, geothermal energy in 2005 generated approximately 16,010 gigawatt hours (GWh) of electricity or about 0.36% of U.S. annual electricity generation. The generation capacity is rated at about 2850 MW.

Numerous exploration and development projects are underway which if successful would double the capacity. Beyond this growth there is still untapped potential for development of additional hydrothermal resources. The U. S. Geological Survey (USGS) [1] estimated about 23,000 MWe capacity for 30 years of identified hydrothermal resources suitable for generation of electricity in the United States and suggested that another 100,000 MWe of resources may be present but not yet identified. A more recent estimate prepared by a panel of experts hosted by the U. S. Department of Energy National Renewable Energy Laboratory [2] estimated that the identified accessible hydrothermal resource suitable for electrical generation is 30,000 MWe for 30 years with an additional 120,000 MWe unidentified. In addition, the U. S. coastal region of Texas and Louisiana contains a significant amount of hot water nearly saturated with methane and with high wellhead pressures. A recent study by the Massachusetts Institute of Technology [3] reported that the thermal energy and energy in the methane may represent as much as 1,000 MWe capacity for 100 years.

2. FUTURE RESOURCES

Although these numbers are significant, they represent only a small fraction of the thermal energy underlying the United States. Current geothermal development is limited to geothermal systems driven by the convective flow of hot water associated with active volcanoes or with deep circulation of fluids. However, the majority of the earth’s thermal energy is contained in areas where heat is transferred by conductive. It is this energy that is truly the future of geothermal energy in the United States.

Since the early 1970s researchers in the U. S., Japan, Europe and more recently private developers throughout the world have looked for ways to tap the conductive heat in the earth. The conceptual model, termed enhanced geothermal systems or EGS, is to drill wells and create or enhance subsurface fractures by the use of reservoir stimulation practices pioneered by the petroleum industry. Such technology offers the promise of tapping the enormous amount of heat contained within the earth. Both research and commercial projects are underway in Australia, France, Germany, Switzerland and the United States.

In the United States several groups of venture capitalists have initiated projects. At this time little is public ally available concerning their work. The U. S. Department of Energy (USDOE) is also working with private developers to investigate stimulation technology in poorly productive areas of commercial geothermal fields.

The USDOE commissioned a study of the potential for enhanced geothermal systems in the United States. The Massachusetts Institute of Technology lead team published their findings in December 2006 [3]. The report is available electronically at http://geothermal.inl.gov or http://www1.eere.energy.gov/geothermal/future_geothermal.html .

The study found that EGS represents a large, indigenous resource that could provide 100 GWe of electrical generation in the next 50 years with a reasonable investment in R&D. The report estimates that the EGS resource base is more than 13 million exajoules of which about 200,000 exajoules may be extractable. That represents 2,000 times the annual consumption of primary energy in the United States.

The USDOE is evaluating the findings of the report and comments from the geothermal and petroleum industries. At this point, creation of a geothermal system with adequate productivity and sufficient size to transfer the heat required for commercial application is the main constraint. Additional technology to drill at reasonable cost to great depth will be needed to recover the thermal energy throughout the United States as well as modification of many of the tools routinely used by the petroleum industry.

3. REFERENCES

[1] L. J. P. Muffler, ed., "Assessment of geothermal resources of the United States – 1978," U. S. Geological Survey Circular 790, 163 p., 1979.
Available: http://pubs.er.usgs.gov/usgspubs/cir/cir790

[2] B. D. Green and R. G. Nix, "Geothermal – The energy under our feet," National Renewable Energy Laboratory Technical Report NREL/TP-840-40665, Golden, Colorado, 16 p., 2006. Available: http://www1.eere.energy.gov/geothrmal/pdfs/40665.pdf .

[3] J. W. Tester, B. J. Anderson, A. S. Batchelor, D. B. Blackwell, Ronald DiPippo, E. L. Drake, J. Garnish, B. Livesay, M. C. Moore, K. Nichols, S. Petty, M. N. Toksöz, and R. W. Veatch, Jr., "The Future of Geothermal Energy," Idaho National Laboratory External Report INL/EXT-06-11746, Idaho Falls, ID, 396p., 2006. Available:
http://geothermal.inl.gov or
http://www1.eere.energy.gov/geothermal/future_geothermal.html.

4. BIOGRAPHY

Allan J. Jelacic is the Acting Program Manager for the Geothermal Technologies Program at the U.S. Department of Energy. He has over 25 years of experience in geothermal energy research and development with the Federal government in various management capacities. Among the major research programs he has managed include: hot dry rock, geopressured-geothermal, magma, and enhanced geothermal systems. He is the U.S. representative to the International Energy Agency Geothermal Implementing Agreement. Dr. Jelacic has a B.S. in geology from the University of Pittsburgh, an M.S. from Yale University, and a Ph.D. from the University of Rochester.

J. L. Renner has been the geothermal lead at the U. S. Department of Energy's Idaho National Laboratory since 1986 and has spent most of his career working with geothermal energy. He began his career with the U. S. Geological Survey in 1970. He has participated in several assessments of the geothermal resources of the United States in 1975. Since then he has participated in reviews of geothermal potential throughout the United States, Africa, the Caribbean and Indonesia.

Mr. Renner holds a B.A in Mathematics from Carleton College and a M.Sc. in Geology from the University of Minnesota. He has authored or co-authored many professional papers. He is a member of the Geothermal Resources Council, Society of Petroleum Engineers, American Association of Petroleum Geologists and American Geophysical Union and has received the Geothermal Resources Council's Joseph Aidlin Award.

).

Received 6 February 2008
Paper 08GM0355

4. Advanced Power Cycles for Enhancing Geothermal Sustainability: 1000 MW Deployed Worldwide

Lucien Y. Bronicki, Chairman, Ormat Technologies, Inc., Reno, NV, USA.

Abstract**—**Until the early 80’s geothermal plants used steam turbines exclusively, operating on dry steam or separated steam. In the mid 80’s the was introduced, initially to enable exploitation of lower enthalpy resources, then to recover the heat from the separated water, and thereafter to handle high gas content resources as well as high enthalpy resources using combined steam/organic cycles [1]. Most of these plants are air-cooled, assuring 100% reinjection of geothermal fluids and thus enhancing sustainability as well as reducing the environmental impact. Today close to 1,000 MW of such plants are deployed worldwide. Examples of commercial plants are given in capacities from 200 kW to 130 MW.

Index Terms**—**Aquifer, depletion, environmental, matching, optimization, Organic Rankine Cycle (ORC), scaling, sustainability**.**

1. INTRODUCTION

To widen the range of resources suitable for power generation beyond dry steam and flashed steam plants, many innovative power cycles have been proposed in the past 20 years, some (such as Kalina, Bi-Phase, etc.) have been experimented with in the last 20 years, but only four are in commercial operation - single and double-flash steam cycles, and two configurations of the Organic Rankine Cycle (ORC): binary and geothermal combined cycle.

Of the 9,000 MW of geothermal plants installed worldwide, most use steam turbines operating on dry steam or steam produced by single or double flash. About 1,000 MW use ORC or steam/ORC combined cycles. [4]

Operational experience has confirmed the advantages of the ORC plants, not only for the low enthalpy water-dominated resources, but also at high enthalpy for aggressive brine or brine with high non-condensable gas content. The air-cooled ORC plants are particularly well adapted to the Engineered Geothermal Systems (EGS). The somewhat higher installed cost of these systems is often justified by environmental and long-term resource management considerations. [5] [6].

2. OPTIMIZATION IN THE DESIGN OF THE POWER CYCLE

The optimization of the whole geothermal power plant system is accomplished by matching the working cycle and fluid properties to the characteristics of the resource, in considering not only the resulting efficiency and cost, but also the impact on the environment, the long-term pressure support, requirements for make-up wells and the O&M costs.

2.1 Heat Cycle Considerations

When the source is a liquid phase only (sensible heat) the ideal cycle would have a varying source temperature, being a succession of infinitesimal Carnot cycles. In a sub-critical Rankine Cycle the constant temperature of the evaporation leads to a loss of energy, however, because of the lower latent heat of vaporization this drawback is lower than in a steam cycle.

This objective of getting closer to the ideal cycle has been aimed at in proposing the super-critical binary cycle, the different total flow regenerative cycle, the cascaded binary cycle and the Kalina cycle.

When dry steam is available the most effective way is to use the conventional condensing steam cycle.

When the source is a mixture of steam and brine and/or has a high content of non condensable gases, the most effective utilization of the resource is achieved through a combined cycle by expanding the steam first in a back pressure steam turbine then the heat of condensation together with the heat of separated brine is used to drive a bottoming ORC.

To compare the efficiency of the different systems it is of course necessary to consider the output net of parasitics, such as cycle pumps, production pumps, injection pumps, cooling systems and non-condensable gas extraction power consumption. [2]

2.2 Resource Considerations

Sustainability is defined as the ability to economically maintain the installed capacity over the life of a plant [3]. In case of geothermal power plants this is controlled by two factors: heat recharge and water recharge.

Sustainable heat flow to the plant, beyond the natural heat recharge is supported by accessing the stored heat through drilling additional wells over the life of the project.

The decline of production in the Larderello, Geysers and Wairakei fields has focused attention on the necessity for long-term pressure support by re-injecting as much as possible of the geothermal fluid.

In addition, in brines rich in carbonates, flashing, as accomplished in conventional steam plants leads to scaling of injection wells thus reducing their life span.

Use of secondary loops and of down hole and booster pumps, as employed in air cooled ORC plants assures complete water recharge and reduces both the fouling of the heat exchangers and scaling of the injection wells.

2.3 Enhanced Geothermal Systems

The value of the air-cooled ORC is particularly important in the case of Engineered Geothermal Systems (EGS), which are very much dependent on the water recovery ratio.

2.4 Environmental Considerations

Use of air-cooled ORC reduces the impact on the environment by re-injection of:

- Non condensable gases (mainly H_2S released by the steam)
- Discharged fluids such as the separated brine (carrying off heavy metals) and blow-down from the cooling towers (chemicals)

3. CONVENTIONAL STEAM TURBINE GEOTHERMAL POWER PLANTS

Geothermal power plants operating from dry steam or from steam flashed from high temperature water employ either:

- Back pressure turbines which exhaust the spent steam to the atmosphere, or
- Condensing steam turbines that condense the steam in water-cooled condensers under vacuum, with the condensate used as make-up water, in the cooling tower (Figure 1).

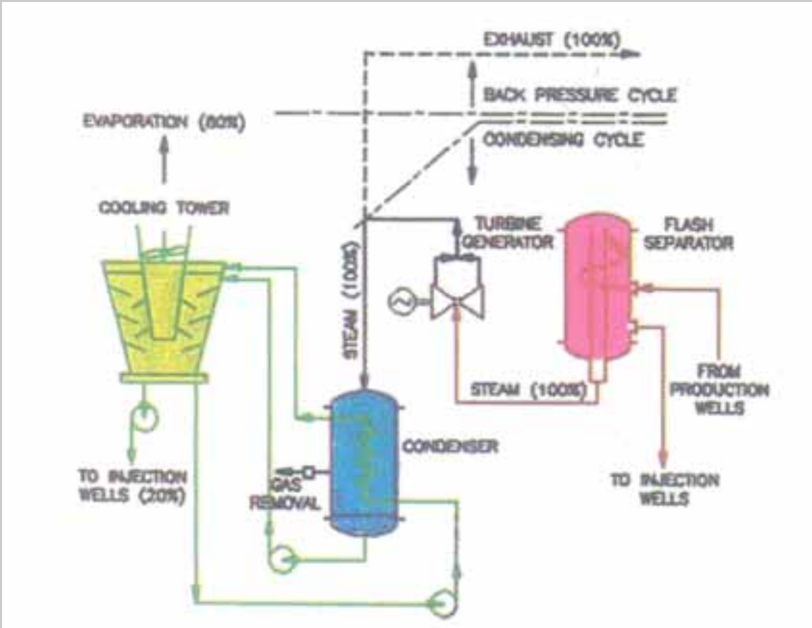


Fig. 1. Conventional Geothermal Power Plant – Back Pressure or Condensing

Backpressure turbines have the lowest capital cost at the expense of lowest efficiency, the condensing steam turbines are more expensive but operate at a higher efficiency than the backpressure turbines.

Both types exhaust the geothermal fluid and rely totally on natural recharge availability. In many cases there is insufficient natural recharge so that the loss of geothermal fluid from these reservoirs results in a reduction of steam production over time. Examples are the Geysers in the USA, the Larderello in Italy, Wairakei and Ohoaki in New Zealand, Momotombo in Nicaragua and Ahuachapán in El Salvador. In these cases the lack of injection has resulted in a drop in power production in the order of up to 40 percent. [2] [6]

4. GEOTHERMAL POWER PLANTS USING ORGANIC RANKINE CYCLE

The basic Organic Rankine Cycle (ORC) as used in an air-cooled binary geothermal plant, is shown on Figure 2 [1]. It is characterized by:

- 100 percent re-injection of the geothermal fluid
- Air-cooling for nearly zero environmental impact; and
- No surface discharge of fluids

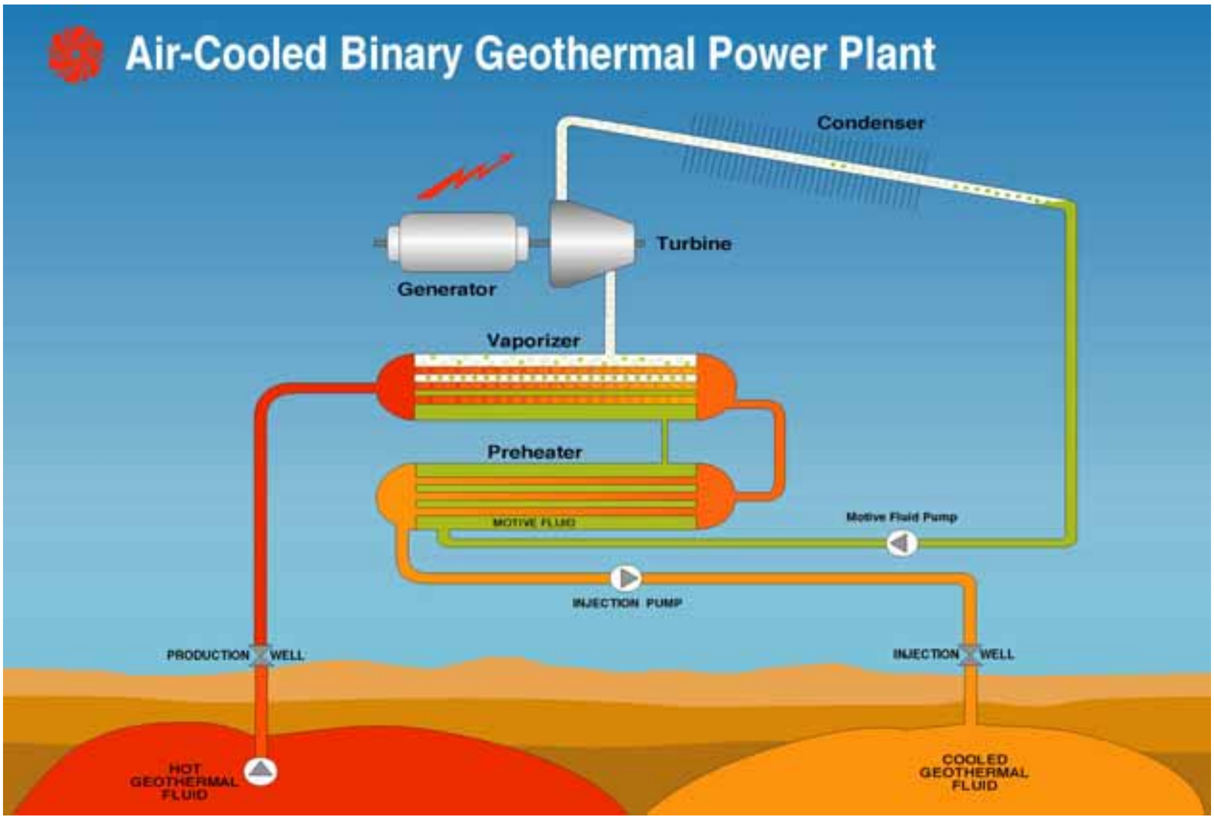


Fig. 2. Air-Cooled Binary Geothermal Power Plant

Different plant configurations have been developed to optimize the use of the geothermal resource. A number of examples are given below.

4.1 Single Phase (Hot Water) Geothermal Power Plants

An example of a single-phase air-cooled binary geothermal plant operating from a liquid type heat source in Hatchobaru, Japan is shown in Figures 2 and 3.

The irreversibility of a binary process on the hot side, namely the temperature difference between the heating fluid and the working fluid, is shown on the temperature vs. heat withdrawn (from the liquid) diagram (Figure 4).

Fig. 3. Single-phase 2.2 MW Hatchobaru Plant in Japan

The marked parts between the two curves represent the irreversibility (losses) of the conversion process. It is clear from this figure that the similarity in shape of the two curves and the proximity between them are good indications of the process efficiency. [8]

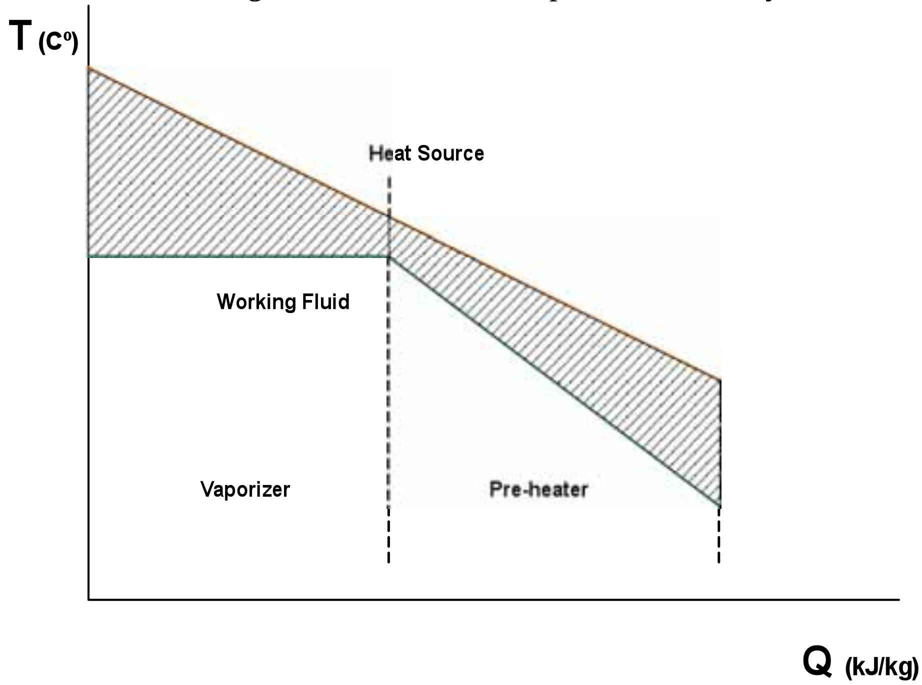


Fig. 4. Typical T/Q Diagram

This loss can be reduced, as shown in Figure 4b, by using a supercritical cycle as indicated earlier, by using a cascading approach [8] and/or by recovering some of the heat of the superheated exhaust vapor to preheat the motive fluid.

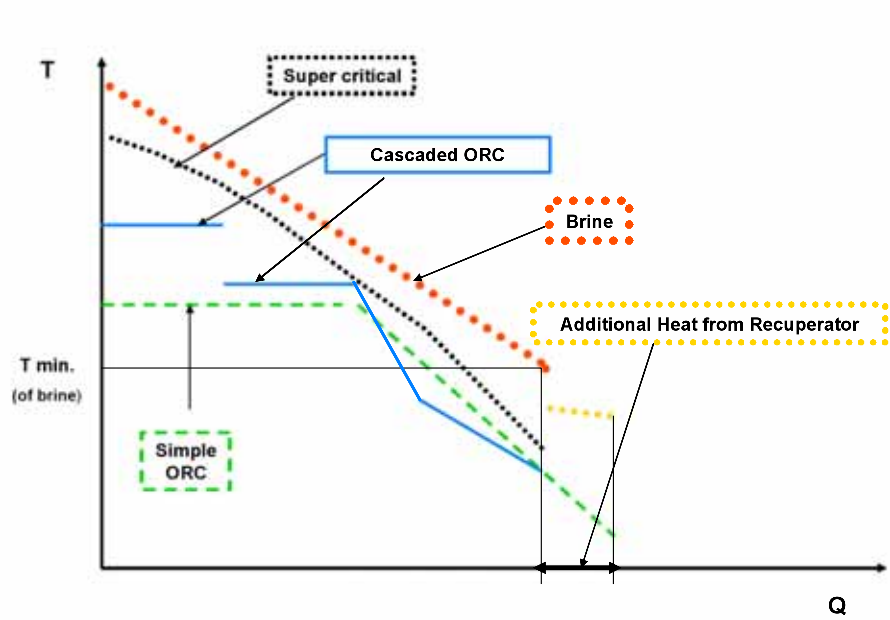


Fig. 4b. T/Q Diagram: Reducing the Irreversibility Loss

4.2 Two-Phase Geothermal Power Plant

In the majority of geothermal fields worldwide the geothermal fluid is separated in an aboveground separator into a stream of steam and a stream of brine. Figure 5 shows such a plant in the Azores.

In a low to moderate enthalpy resource the steam quality is 10 to 30 percent as a function of fluid enthalpy and separation pressure. The two streams can very efficiently be utilized in a two-phase geothermal plant as shown in Figure 6. Separated steam (usually with some percentage of Non-Condensable Gases or NCGs) is introduced in the vaporizer to vaporize the organic fluid.

Fig. 5. Two-phase 14 MW Ribeira Grande Plant in the Azores

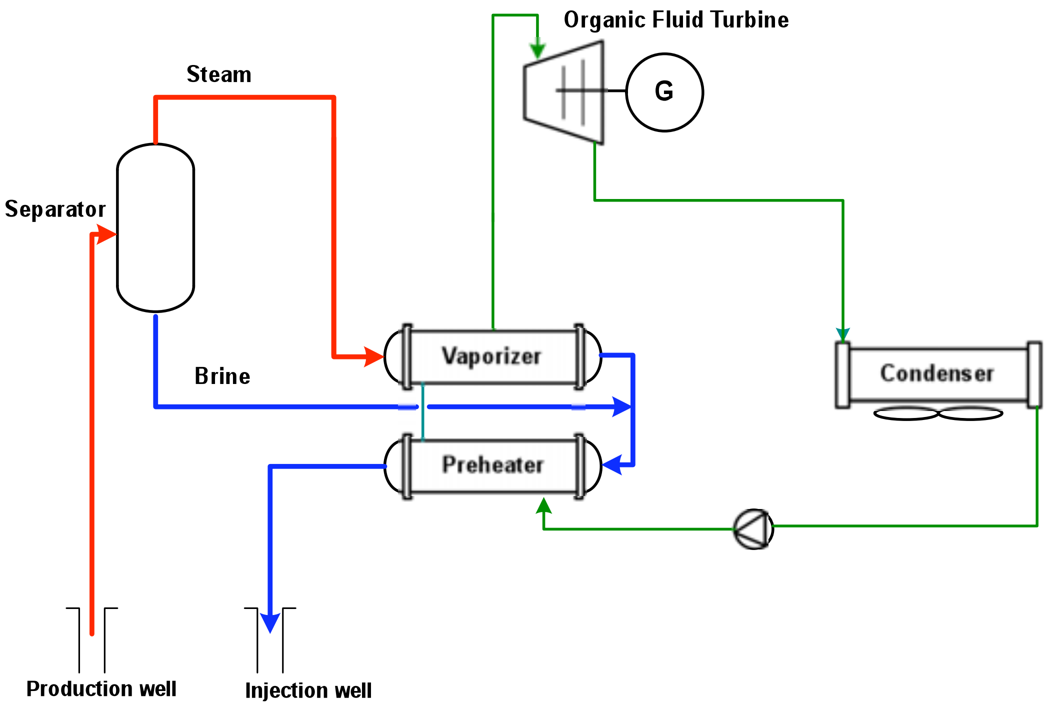


Fig. 6. Two-Phase Power Plant

The geothermal condensate is mixed with the separated brine to provide the preheating medium of the organic fluid. In the ideal case, as presented in the flow temperature diagram (Figure 7), the latent steam heat would be equal to the heat of vaporization of the organic fluid and the sensible heat of the brine plus condensate would be equal to the heat required to preheat the organic fluid. This “perfect” match of heat transfer between the geothermal fluid and the working fluid represents maximum thermodynamic efficiency with minimum losses.

Fig. 7. Ideal Case

4.3 Recuperated Organic Rankine Cycle

In most of the actual cases, the perfect match as above is not feasible, mainly because of limitation in the cooling temperature of the brine and condensate mixture. The limiting factor in most of the cases is the silica scaling risk, which is increased as the brine temperature drops. A method to partially overcome the cooling temperature limit is to add a recuperator that provides some of the preheating heat from the vapor exiting the turbine.

The recuperator is applicable when the organic fluid is of the “dry expansion” type, namely a fluid where the expansion in the turbine is done in the dry superheated zone and the expanded vapor contains heat that has to be extracted prior to the condensing stage (Figures 8 and 9). The recuperated Organic Rankine Cycle is typically 10-15 percent more efficient than the simple Organic Rankine Cycle [7]. This applies also to the two-phase geothermal power plant.

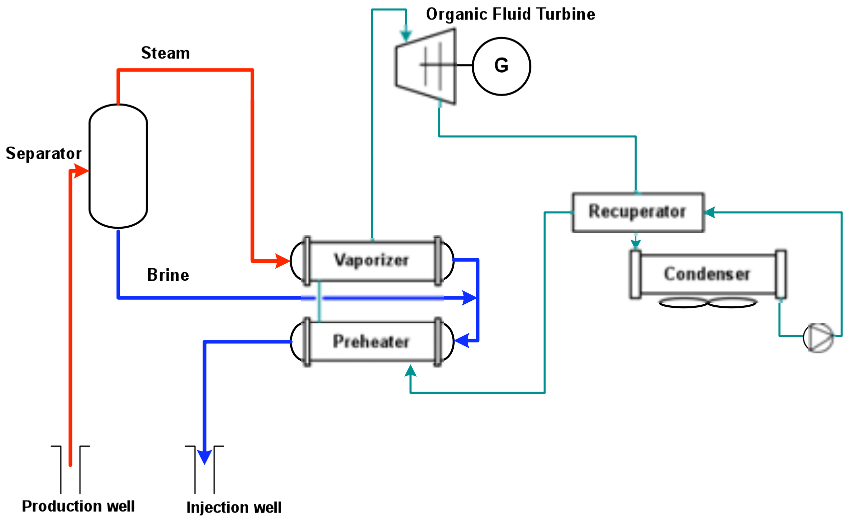


Fig. 8. Recuperated Organic Rankine Cycle in a Two-phase Power Plant

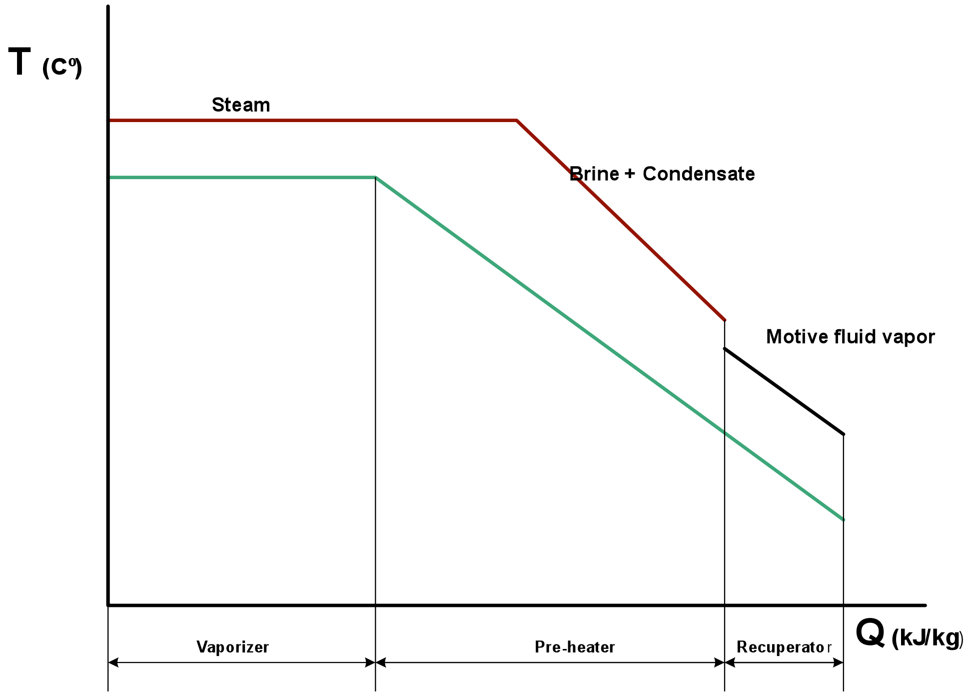


Fig. 9. Recuperated ORC in a Two-phase Power Plant

The recuperated two-phase process is used by Ormat in many geothermal projects all over the world, such as 20 MW Zunil in Guatemala,14 MW Ribeira Grande I and II in San Miguel in the Azores (Figure 5), 1.8 MW Oserian and 13 MW Olkaria III in Kenya.

4.4 Higher Enthalpy Two-Phase Geothermal Power Plant

When the resource enthalpy is higher and as a result, the proportion of steam in the total fluid increases, the "perfect match" between the heat source and the working fluid is not maintained. Thus, some of the available heat or the available energy is lost for power generation.

To utilize the two-phase heat source in a more efficient manner, one can use a secondary organic loop, which uses the extra steam available. The cycle is shown in Figure 11 and is feasible when vapor extraction is possible within the expansion phase of the organic cycle. The simplest way to perform the extraction is with two turbines in series. In this case, some vapor is extracted between the high pressure and the low-pressure turbines and is condensed at an intermediate pressure (and temperature).

The condensed vapor preheats the main organic fluid stream as it exits the recuperator. The extracted organic fluid forms a secondary cycle that generates an additional 5 to 8 percent electrical power. When there is extra steam compared to brine (higher enthalpy) the above cycle is effective and the cooling temperature of the brine plus condensate is limited.

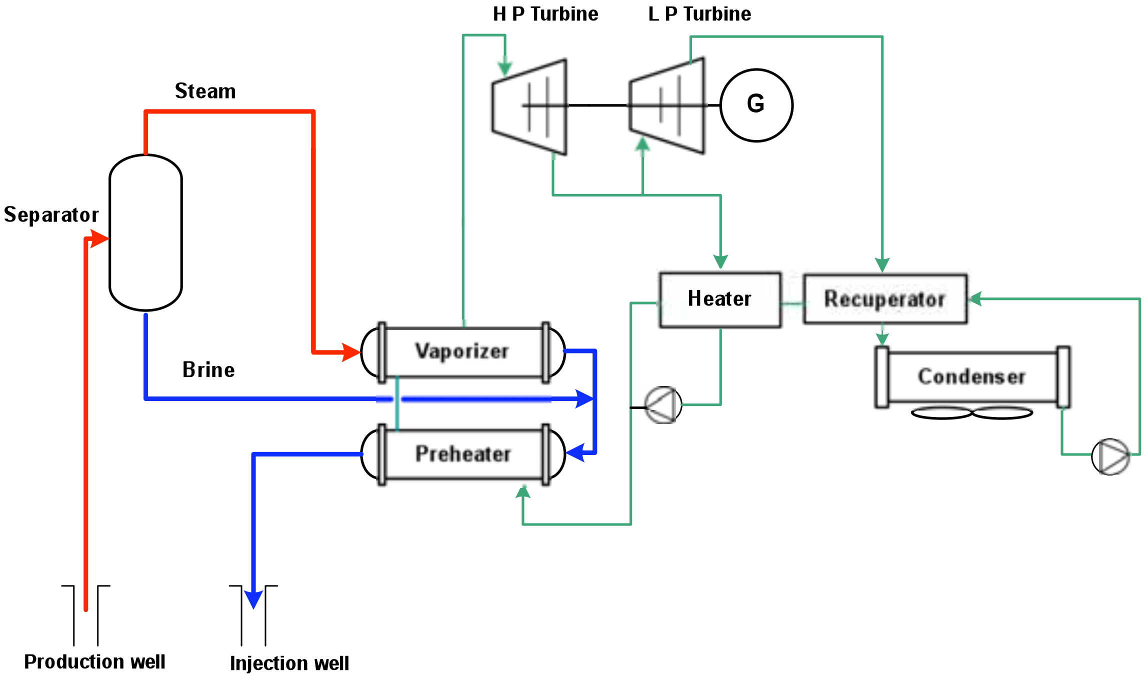


Fig. 10. Secondary Organic Loop Cycle

Figure 11 is a flow temperature diagram of the higher enthalpy cases. Line A is the simple two-phase cycle preheating phase. The significant irreversibility is represented by the large space between the steam and brine lines and line A. Line B shows the preheating phase in a recuperated two-phase cycle; the irreversibility is reduced and the cycle efficiency is increased accordingly.

The third line – C – demonstrates the additional gain in efficiency by using the two-phase/extraction cycle. The line moves further to the right, thus decreasing the gap between the heating line and the working fluid line. Another indication of the increase in efficiency from cycle A to B and to C, is the increasing heat quantity for heating the working fluid, as presented by points QA, QB, and QC.

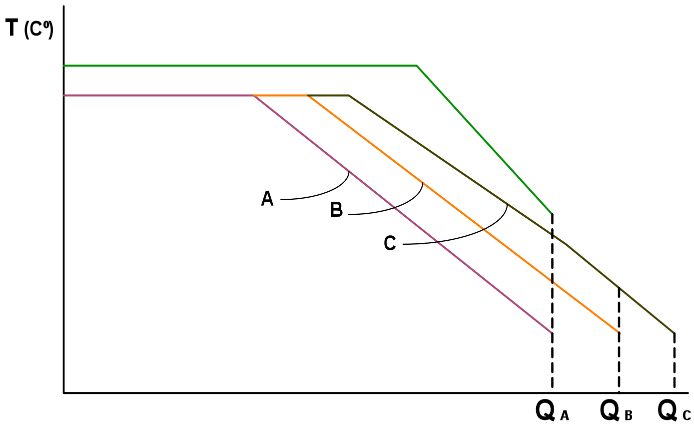


Fig. 11. Higher Enthalpy

4.5 Use of a Back Pressure Steam Turbine

Another approach for the higher enthalpy two-phase heat source is the use of a back pressure steam turbine which generates extra power from excess steam not required for the vaporizer of the ORC.

Part of the preheating of the organic fluid is now done with low-pressure steam exiting the backpressure steam turbine (Figure 12).

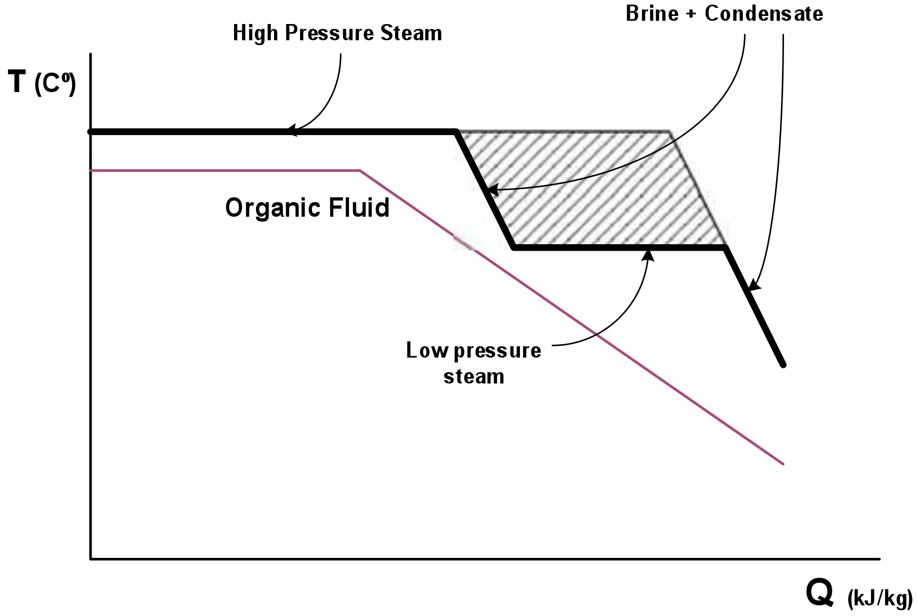


Fig. 12. Pre-heating Using Exhaust in a Back Pressure Steam Turbine

The gap between the steam and the preheating line of the organic fluid could be filled even more efficiently by a multi-stage (two or more) back pressure steam turbine, with extraction of steam between the stages, but the decision on the number of stages is based on the consideration of the trade-off in the process optimization between higher efficiency and the complication (and cost) of the system.

Fig. 13. 20 MW Amatitlán Power Plant in Guatemala

A system based on the above cycle is now operating in the 20 MW Amatitlán geothermal project in Guatemala. (Figures 13 and 14).

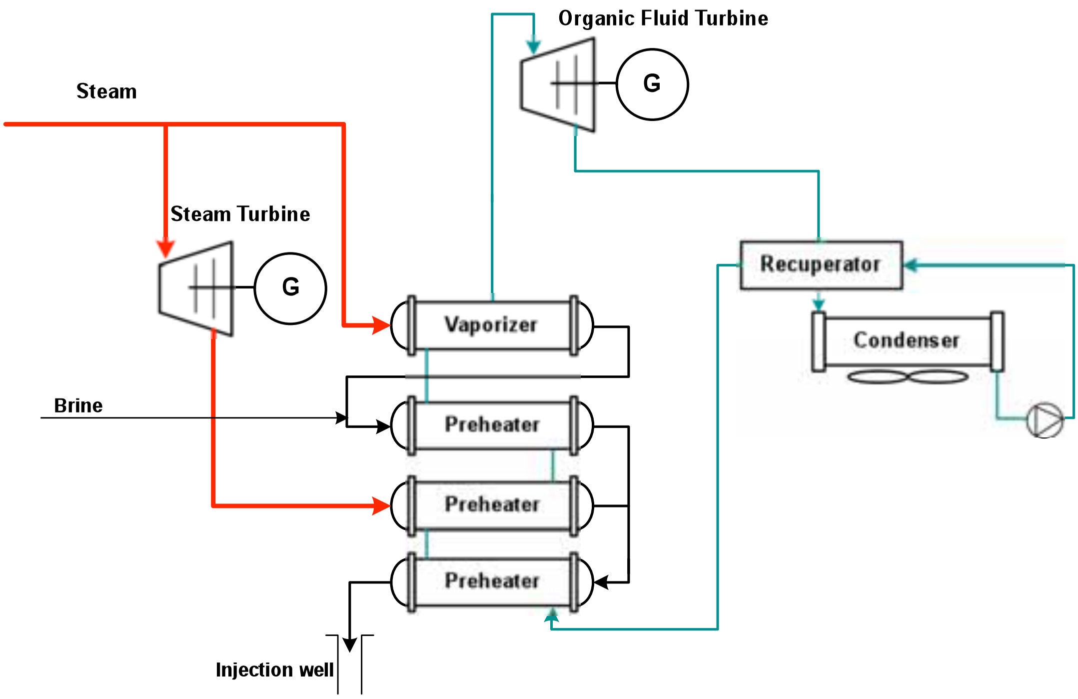


Fig. 14. Block Diagram of the Amatitlán Project

4.6 Geothermal Combined Cycle [9]

For high enthalpy fluids with very high steam content a solution is the geothermal combined cycle configuration where the steam flows through the back pressure turbine to the vaporizer, while the separated brine is used for preheating or in a separated ORC (Figure 15) [9].

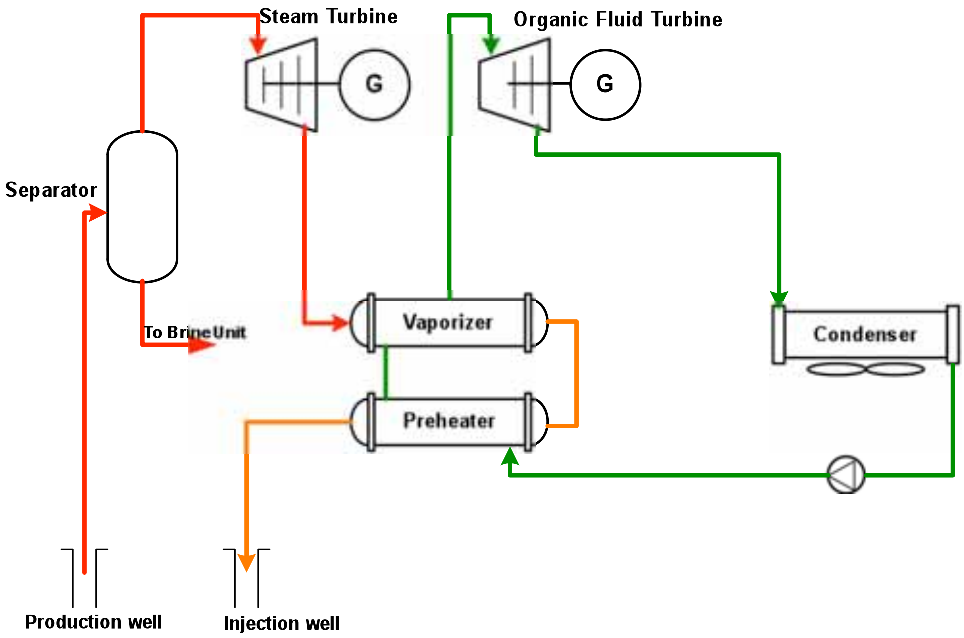


Fig. 15. Geothermal Combined Cycle

This configuration is used in the 125 MW Upper Mahiao in the Philippines (Figure 16), 100 MW Mokai 1 and 2 in New Zealand (Figure 17), as well as in the 30 MW Puna plant in Hawaii.

Fig. 16. 125 MW Upper Mahiao Geothermal Power Plant in the Philippines

Fig. 17. 100 MW Mokai 1 and 2 Geothermal Power Plants in New Zealand

5. DEPLOYMENT

As of 2007 the capacity of geothermal plants using advanced power cycles worldwide is close to 1,000 MW, approximately 10% of the total geothermal capacity installed in the last 50 years. Figure 18 shows the deployment of these plants.

Breakdown of the 1,000 MW in commercial operation is as follows: 60 MW of ORC plants designed or built by Ben Holt, Turboden and Barber-Nichols; one 2 MW of Kalina cycle plant and more than 900 MW of ORC and combined cycle plants.

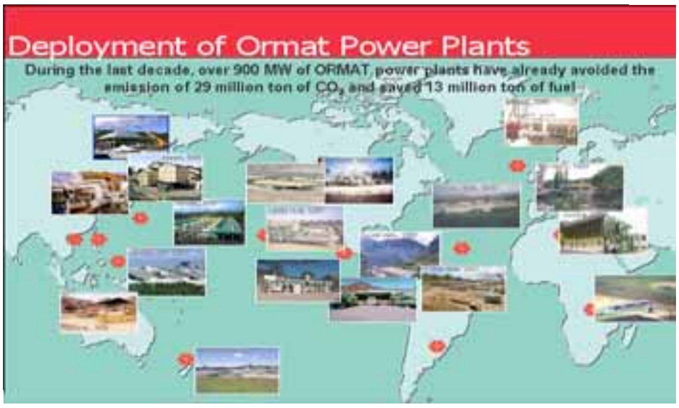


Fig. 18. Deployment

6, ENHANCING SUSTAINABILITY AND COST EFFECTIVENESS

Geothermal resources are complex geological structures that provide conduits for the natural heat of the earth to heat underground waters that may then be used to convey this heat to the surface. Technology to assess the heat content of geothermal resources is available, along with drilling technologies to access this heat and mature proven power technologies to convert this heat to commercial electricity.

The key to the sustainability of this power generation lies in not depleting the waters that convey this energy to the surface.

The use of field-proven air-cooled Organic Rankine Cycle based geothermal power enables the achievement of these objectives by extending the lifespan of the wells and reducing emissions.

Hence cost effective power is generated with enhanced sustainability, mitigating the depletion of the geothermal resources, an element particularly important in the case of the proposed Engineering Geothermal Systems.

8. REFERENCES

Technical Reports:

[1] Bronicki L.Y., “Geothermal power stations”, Encyclopedia of physical science and technology, third edition, vol. 6, 2002.

[2] Wilson S.S. and Radwan M.S., “Appropriate thermodynamics for heat engine analysis & design,” Int. J. Mech. Eng. Educ., vol.5, No. 1977.

Papers from Conference Proceedings (Published):

[3] Subir K. Sanyal, “Sustainability and renewability of geothermal power capacity”, Proc. World Geothermal Congress 2005, Antalya, Turkey, 24-29 April 2005.

[4] Bronicki, L., “Innovative geothermal power plants, fifteen years of experience,” World Geothermal Conf., Florence 1995.

[5] Paula E. Blaydes, “Environmental advantages of binary power plants can enhance development opportunities”, Trans. Geothermal Resources Council, vol. 18, October 1994.

[6] Tom Flynn, “Geothermal sustainability, heat utilization and advanced Organic Rankine Cycle”, Trans. Geothermal Resources Council vol. 26 / Number 9, September/October 1997.

Patents:

[7] H. Tabor and L. Bronicki, "Vapor turbines", U.S. Patent. 3 040 528, June 26, 1962.

[8] Z. Krieger and A. Moritz, "Cascaded power plant using los and medium temperature source fluid", U.S. Patent. 4 578 953, April 1, 1986.

[9] Z. Krieger and U. Kaplan, "Apparatus and method for producing power using geothermal fluid", U.S. Patent. 6 009 711, January 4, 2000.

BIOGRAPHY

Lucien Y. Bronicki is the Chairman and Chief Technology Officer of Ormat Technologies Inc. He founded Ormat in Israel and in 1972 established Ormat in the US.

Before establishing Ormat he worked at the Nuclear Research Center in Saclay (France). He then joined the National Physical Laboratory of Israel, to develop a solar energy powered turbine.

He holds a B.Sc. in Mechanical Engineering, an M.Sc in Physics from the University of Paris and a postgraduate degree in Nuclear Engineering from CNAM in Paris.

Mr. Bronicki has authored or co-authored many professional articles and holds 40 patents on thermodynamic devices, turbines and controls.

He was a member of the Studies Committee "Energy for Tomorrows World Commission" of the World Energy Council and is a member of the Executive Council of the Weizmann Institute of Science. He is also a member of the IEEE, ASME, the International Solar Energy Society, and the Geothermal Research Council. He received the Geothermal Research Council Pioneer's Award, a PhD Honoris Causa from the Weizmann Institute of Science and from the Technion.

Received 19 March 2008
Paper 08GM0618

5. Geothermal Power Plants in the Hengill Area

Ingólfur Hrólfsson, Orkuveita Reykjavikur, Reykjavík, Iceland
Sigurgeir Bjorn Geirsson, Orkuveita Reykjavikur, Reykjavík, Iceland.

Abstract-- The Hengill area in SW-Iceland is one of the most extensive geothermal areas in Iceland. Orkuveita Reykjavíkur operates two power plants on the Hengill area. The company is working on an Environmental Impact Assessment for two new power plants in the area. Power plants on the Hengill area will produce at least 600 MW_{el} and 433 MW_{th} by the end of 2011 The company is also working on research projects connected with it's power plant project; the Carb-Fix project and IDDP project. This paper describes the Hengill area, Orkuveita Reykjavíkur's power plants and research projects in the Hengill area.

Index Terms-- Drilling, Environmental factors, geothermal energy, geothermal power generation, Power plants, Power systems, Research and development, Steam generation, Water heating.

1. INTRODUCTION

The Hengill area in SW-Iceland is one of the most extensive geothermal areas in Iceland. It is located 25 km east of Reykjavík (Fig. 1). It is approximately 110 km² and it is estimated to sustain 700 MW_{el} power production in several power plants [1].

Research drilling started in 1965 at Nesjavellir in North of Hengill (Fig. 1). In 1990 hot water production for the district heating in Reykjavík started in the Nesajvellir plant. Power production started there in 1998. Today Nesjavellir power plant produces 120 MW_{el} and 300 MW_{th}. The Nesjavelir plant was built in several stages.

To meet increasing demand for electricity and hot water for space heating in the industrial and the domestic sectors Orkuveita Reykjavíkur (OR) is currently building a CHP geothermal power plant at Hellisheiði (Fig 1). The same approach is used for the Hellisheiði plant; as for Nesjavellir i.e. it will be built in several stages. The first stage, which came into operation in 2006, consist of two 45 MW_{el} units. The second stage of the Hellisheiði power plant, which consists of a 33 MW_{el} Low Pressure Unit, started operating in November 2007. The construction of the third stage of the power plant is in progress that is the erection of a two additional high-pressure units, 45 MW_{el} each. Erection of the thermal plant, the fourth stage, starts in the beginning of year 2008.

OR is also planning to build at least two new geothermal power plants in the Hengill area, in Hverahlíð and Bitra (Fig. 1).

An environmental impact assessment (EIA) for the power plants at Hverahlíð and Bitra is under work and will be published in the fourth quarter of 2007.

The capacity of the Hellisheiði Power plant will be 300 MWe electric and 400 MW_{th} thermal. Estimated capacity of the power plants in Hverahlíð and Bitra will be 90 MW_{el} and 135 MW_{el} respectively.

With more knowledge of the Hengill geothermal area accumulated through running the Nesjavellir and Hellisheiði power plants and research drilling new opportunities arises which can be utilized both in future power plants in the area and in other projects.

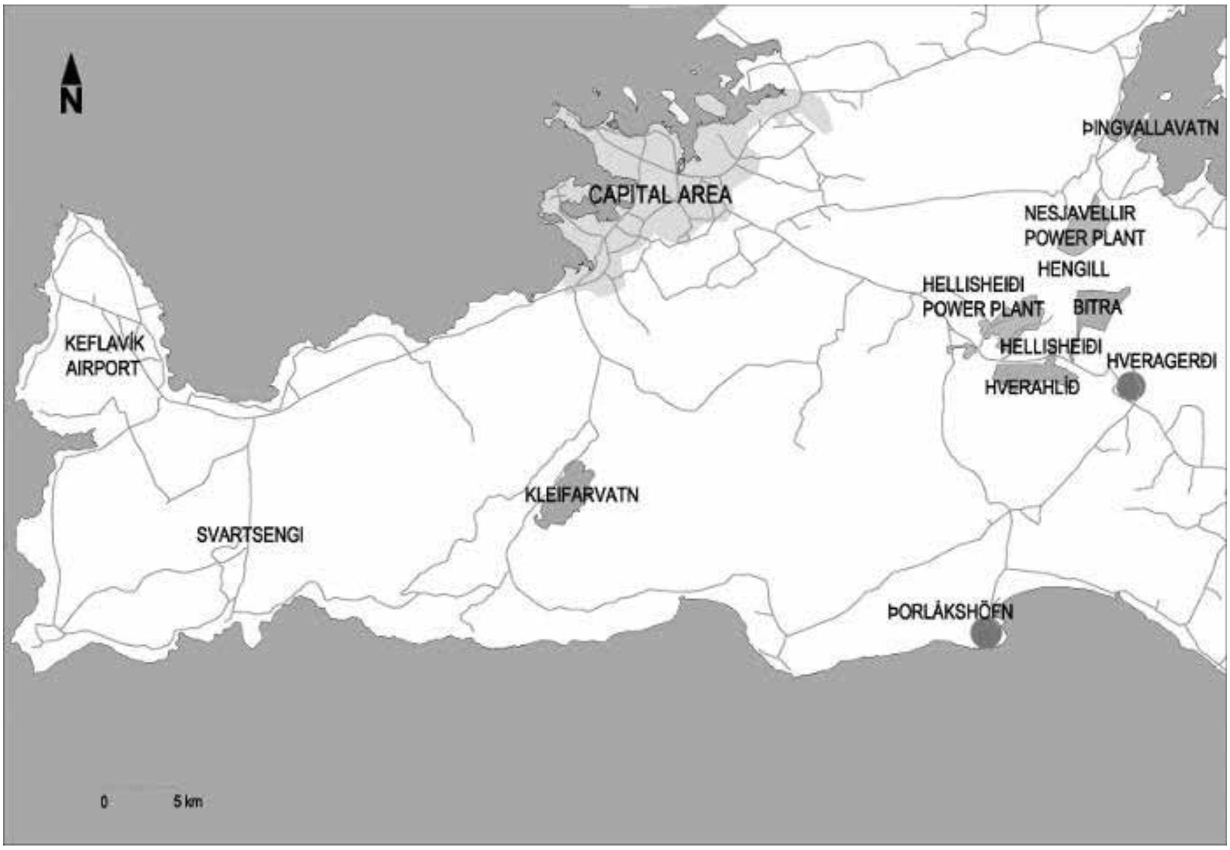


Fig. 1. The locations of OR's power plants in the Hengill area.

2. THE HENGILL AREA

The Hengill area is a rural mountainous area in the middle of the western volcanic zone in Iceland that runs from Reykjanes in a northerly direction to Langjökull (fig 2). The Hengill region is one of the most extensive geothermal areas in the country. Surface measurements and heat distribution indicate an area of around 110 km² and it is estimated to sustain 690 MW_{el} power productions in several power plants [1]. The high temperature geothermal area at Hengill covers three central volcanoes and their surroundings. The youngest one is the most active, where as the oldest one is eroded but still geothermal active.

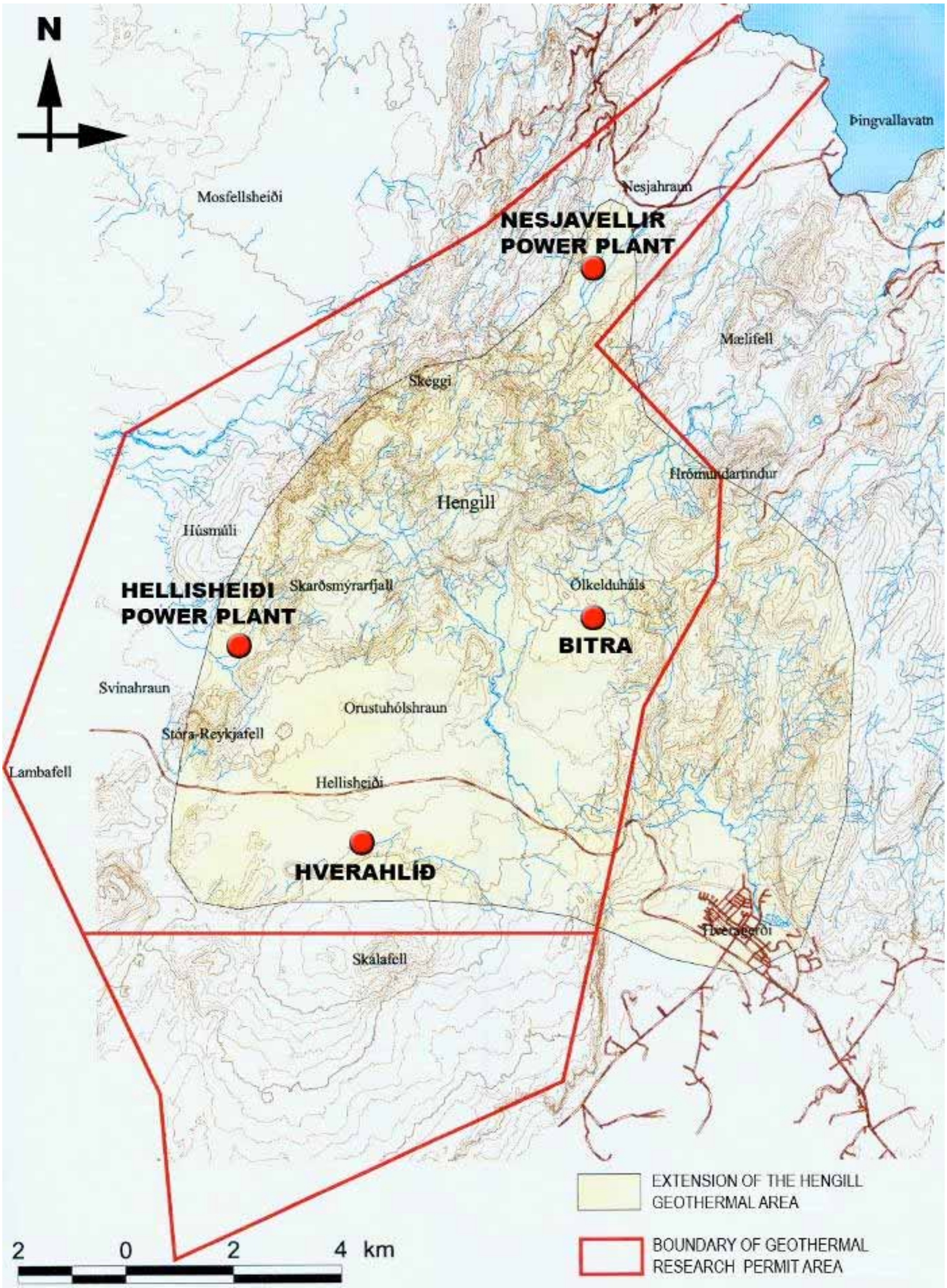


Fig. 2. Detailed map of the Hengill area.

Areas, that are already utilized by OR are under construction, lie on the active fault zone of the youngest volcanic feature of the Hengill area that reaches from Nesjavellir in the north to Hellisheiði in the south, about 30 km in length. A fault zone that is part of the Hengill Volcano cuts through the volcanic zone from southwest to northeast. The most important areas for productions in the Hengill area are connected to this fault zone, i.e. Nesjavellir in the north and

Hellisheiði in the south. Three recent volcanic fissures are among the features that characterize these areas. They erupted 10, 6 and 2 thousand years ago. These volcanic fissures are considered the main sources of geothermal energy at Nesjavellir and Hellisheiði.

3. NESJAVELLIR POWER PLANT

OR’s first geothermal power plant in the Hengill area is Nesjavellir power plant (Fig 3). Construction of the power plant began in early 1987, with the first stage being completed in May 1990. Four holes, generating about 100 MW_{th}, were then connected to the processing cycle, The next stage of power harnessing was brought online in 1995 when the fifth hole was connected; heat exchangers and a deaerator were added; and the production capacity was increased to 150 MW_{th} of geothermal power [2].

In fall 1998, the first steam turbine was put into operation and the second in end of the year, producing total of 60 MW_{el}. Five additional holes were put online, increasing the total processing power of the power station to 200 MW_{th}, In June 2001 the third turbine were put into operation the turbines are 30 MW_{el} each, making the total production of electricity 90 MW_{el} [2].

Fig. 3. Nesjavellir power plant.

Today Nesjavellir power plant generates 300 MW_{th} and 120 MW_{el}. The power plants operate on 23. OR is currently researching the Nesjavellir area to see if it is possible to add one more turbine to the power plant.

4. HELLISHEIÐI POWER PLANT

The first research drilling for the Hellisheiði power plant (Fig. 4) was in 1985 and then again in 1994. These boreholes indicated that the geothermal fields could sustain power production but more drilling was needed before decisions could be made. In 2001 and 2002 five boreholes were drilled. Based on the results from these boreholes it was decided to start preparations for a power plant with total capacity of 120 MW_{el} and 400 MW_{th} with the objective to meet increasing demand for electricity and hot water for space heating in the industrial and the domestic sectors.

Fig. 4. Hellisheiði power plant.

Drilling continued and by the end of 2005 18 new boreholes had been drilled. In light of the results of these drillings it was decided to enlarge the development area further north towards the main volcano. With this new area the estimated capacity of the geothermal area was increased by 120 MW_{el}. The first stage from this new area is 90MW_{el} to be ready in 2008. With this enlarged potential more geothermal water was available than initially estimated and more than is needed for the thermal plant. Therefore it was decided to add one low-pressure unit to increase the utilization of the geothermal energy. Its size ended as 33 $MW_{el.}$

The first stage started operating in 2006 and consist of two 45 MW_{el} units. The second stage, a 33 MW_{el} Low Pressure Unit, started operating in November 2007. The construction of the third stage is in progress that is the erection of a two additional high-pressure units, 45 MW_{el} each. Erection of the thermal plant starts at the beginning of year 2008.

4.1 Construction plan

Hellisheiði power plant is built up similar to Nesjavellir power plant, it’s a cogeneration plant and it is built in modular units. Then the power plant can grow as the market demand increases and also utilize greater knowledge of the geothermal capacity of the area which drilling provides.

The power production capacity of each electric unit will be 45 MW_{el} and 33 MW_{el} for the Low Pressure Unit. For each thermal unit the capacity will be 133 MW_{th}. Table 1 shows the main construction stages for Hellisheiði power plant and when each stage will start operating

TABLE I

MAIN CONSTRUCTION STAGES FOR HELLISHEIÐI POWER PLANT

Com-missioning	2006 MW_{el}	2007 MW_{el}	2008 MW_{el}	2009 MW_{th}	2910 MW_{el}	>2011 MW_{el}
Electricity						
High Pressure	1 st. 90		3 rd. 90		5 th 90	
Low Pressure		2 nd. 33				
Thermal unit				4 th 133		267

4.2 Preparation and construction face

The first step was to find consultants for the project. It was done in open tender on the international market. The job went to a consortium of 6 Icelandic companies with long established experience in Iceland.

For the Environmental Impact Assessment (EIA) use was made of the extensive research carried out over several years by Orkuveita Reykjavíkur. The EIA was finalized by the end of the year 2003. EIA for the extension to Skarðsmýrarfjall was accepted two years later. In both cases the environmental impact was considered low [3], [4].

The work was divided into several contracts of varying sizes. There are several reasons for this. The main ones are speed, special Icelandic conditions and the size of the Icelandic contractors. The biggest contracts are for drilling, turbines, generators and cold end and for civil construction. This policy of calls for lot of work in design and coordination but this gives OR much better control over the final product than would be possible in a turnkey project.

4.3 Technical description

The total development area of Hellisheiði power plant is 820 ha. The development consists of geothermal utilization, access roads, service roads, production wells, water supply system, steam transmission pipes, steam separator stations, power house, cooling towers, steam exhaust stacks, a fresh groundwater supply system, water tanks, hot-water transmission pipe, quarrying, discharge system, injection areas and connection to the power grid

4.4 Production wells and directional drilling

Production wells are drilled both vertical and directional, up to five wells per drilling site. With directional drilling it is possible to reach under valleys and in the direction of the mountain Hengill, without disrupting the valleys. Production wells can be up to 3.000 m and with directional drilling it is possible to drill 1.200 m from center (Fig. 5).

Production wells are grouped on drilling sites up to five wells on predefined areas. Mean number of production wells per drill site is four with an area of about 12.000 m2. The localization of drill sites depends on geothermal and geophysics researches. Visualization of drill sites in the landscape has also a great impact on the situation of the drill sites. Minimum distance between production wells on a drill site is around 10 m.

Wellhead silencers and borehole housings are installed at each well.

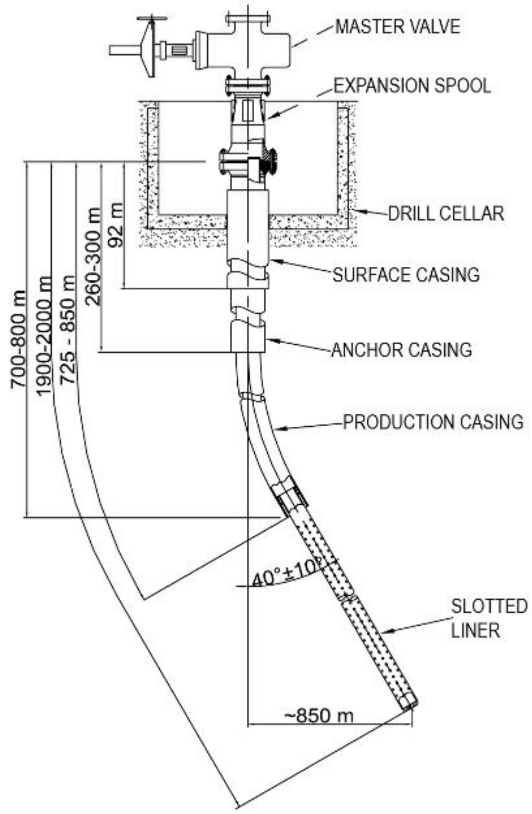


Fig. 5. Directional drilling.

4.5 Flow diagram for Hellisheiði power plant

Fig 6 shows a flow diagram for Hellisheiði power plant.

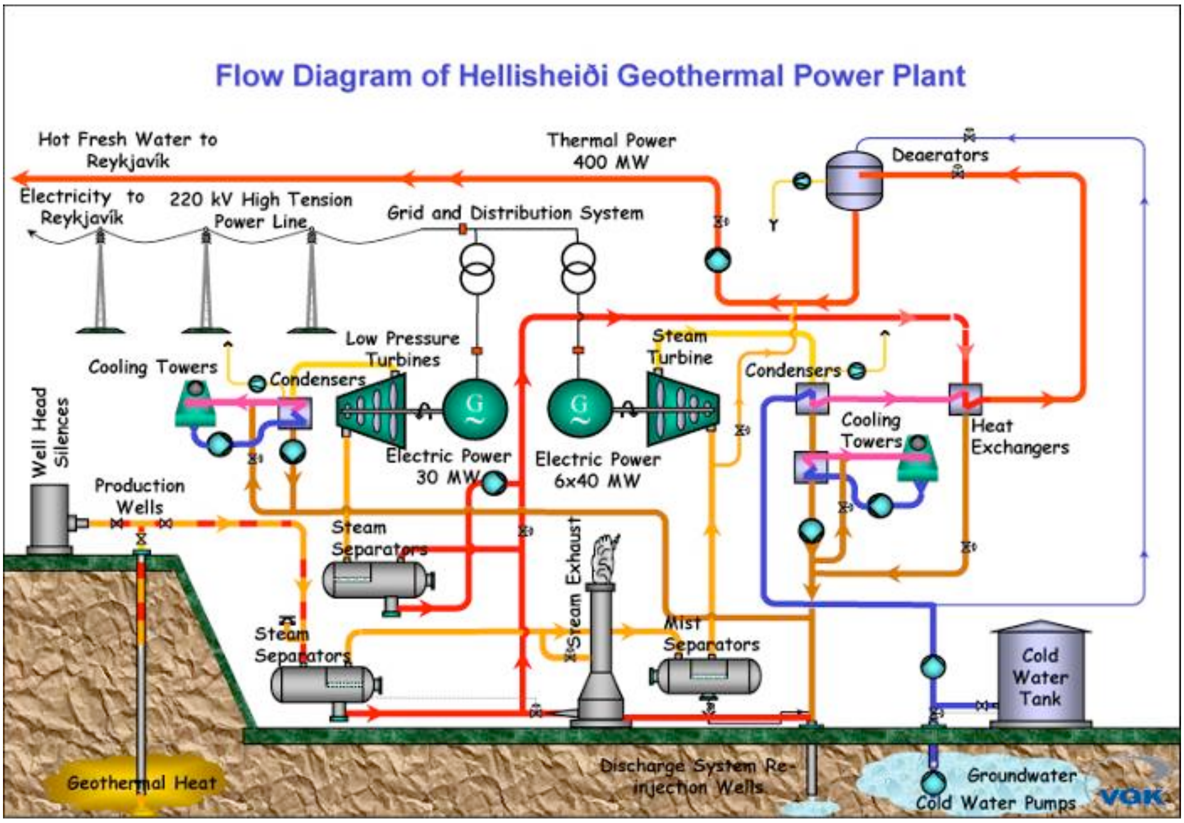


Fig. 6. Flow diagram of Hellisheiði power plant.

Geothermal fluid that flows from the boreholes is collected in the separator stations. From the separator stations, steam and separated hot water is transported in separate pipelines to the power station, where electricity and hot freshwater is produced.

From mist eliminators in front of the power station, steam flows into steam turbines through stop valves and control valves on each power unit.

It is assumed that six power units, each 45 MW_{el}, will be installed in the power station. Estimated steam demand for each power unit is 89 kg/sec.

After flowing through the turbines, steam flows into a condenser where it condenses. Steam is condensed in the condenser with two ways. One is with cold groundwater from groundwater boreholes, this acts as the first step of the hot freshwater production, the other way is with circulation cooling water from cooling towers. The division of the cooling will be determined with the hot freshwater demand. Part of the condensed steam from the condenser is added to the circulation cooling water, but remaining condensed steam is transported to discharge system [3].

Separated hot water from the separator station is used for electricity production and final heating of preheated water for hot freshwater production. By dropping the pressure down to 2 bars the separated water boils and part of it turns to steam. The steam is separated from the fluid in separators and transported to low-pressure steam turbine power unit that can produce 33 MW_{el}. The steam in this power unit is cooled with circulation cooling water only. Part of the condensed water is used in the cooling water circulation to substitute water that evaporates in the cooling tower. The rest is transported to the discharge system [4].

The final heating of the preheated freshwater from the condensers takes place in the heat exchangers in the thermal power station where its temperature goes up to 100°C. Separated geothermal water is used for heating in the heat exchanger and then it is transported to the discharge system. From the heat exchangers the preheated water is transported to the deaerator where dissolved oxygen is removed with boiling. After that a small amount of geothermal steam, which contains H_2S is mixed into the preheated water in order to prevent corrosion. From the thermal power plant, the preheated water is pumped through hot water pipelines into distribution tanks in Reynisvatnsheiði [3].

Condensed water and separated geothermal water is transported in a pipeline from power plant to the discharge area [3].

5. HVERAHLÍÐ AND BITRA

Because of a growing demand for electricity in the industrial sectors, for example aluminum smelters, computer server farms and silicon factory, OR decided to start planning two new power plants at the Hengill area; Bitra power plant and Hverahlíð power plant.

5.1 Environmental policy

Project of building new geothermal power plants are subject to EIA according to Article 5 and item 2 of Annex 1 of the Icelandic EIA Act no. 106/2000. Preliminary EIA proposals for the project at Bitra and Hverahlíð were presented in August 2006 and work on the EIA has been in progress since then. It is estimated that the Planning Agency will issue their conclusion regarding the EIA in the beginning of 2008.

OR is determined to be a leader in matters concerning the environment, and that environmental management should be one of the company's priorities. OR put a lot of effort in the EIA for the power plants in Bitra and Hverahlíð to define how the new power plants and their development area can be environmental friendly. In order to do that the power plants will be designed so they will fit into the landscape with minimum effect. The following list describes few methods to fulfill this prerequisite [5] and [6]:

Production wells will be grouped on pre-defined drilling sites. The area of the drilling sites will be minimized and steam transmission pipes on the drilling sites will be in underground shafts. Well head silencers and other equipment for the boreholes will be placed in semi-hidden buildings. Up to 8 boreholes can be placed on each drilling site instead of 5 like it is in Hellisheiði power plant

The steam transmission pipeline will be adjusted to the landscape. OR has defined three types of steam transmission types which will be used based on the environment the pipelines are in:

Hidden steam pipes, which will be buried (Fig. 7).

Semi hidden steam pipes are normal steam pipes on the surface, but mounted earthen barriers will be used to minimize the effect of the pipelines in the landscape (Fig. 7).

Normal steam pipes are on the surface. No surface work will be done around the steam pipes, but their color and polish will be chosen according to the landscape (Fig. 7).

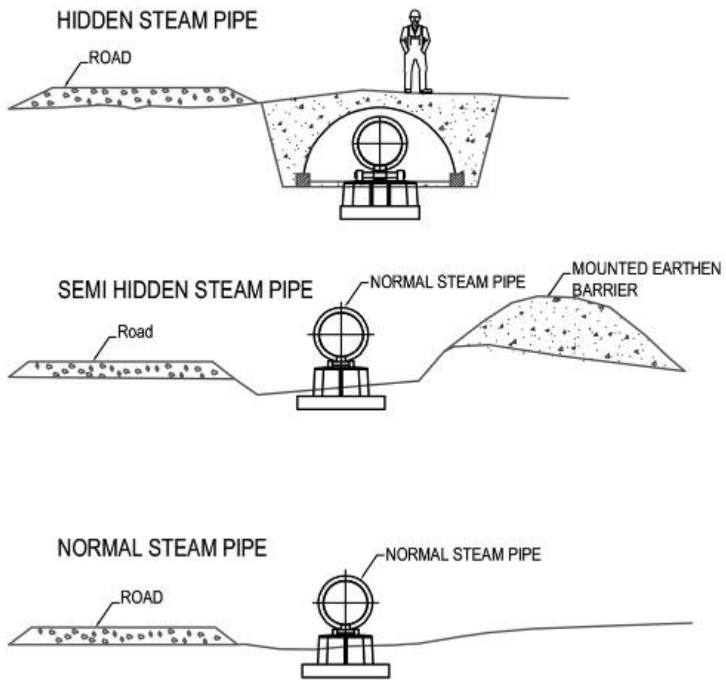


Fig. 7. Types of steam pipes.

The main powerhouse will be designed in harmony with its surroundings. It will also be hidden or semi-hidden from pre-defined key viewpoints.

All buildings will be painted in colors so they will meld with their surroundings and if necessary they will be semi-buried in the ground.

The cooling towers will be hybrid type cooling towers. The hybrid towers head up the steam from the cooling tower so that almost all steam will disappear from the cooling towers in most weather conditions.

5.2 Power plant at Bitra

The development area is located about 8 km northeast of Hellisheiði power plant. The development area of the power plant was reduced from its original size because of environmental reason. (Fig. 8). Because of the reduction of the development area and OR’s environmental policy the effect of the Bitra power plant on it’s surroundings has been minimized [5].

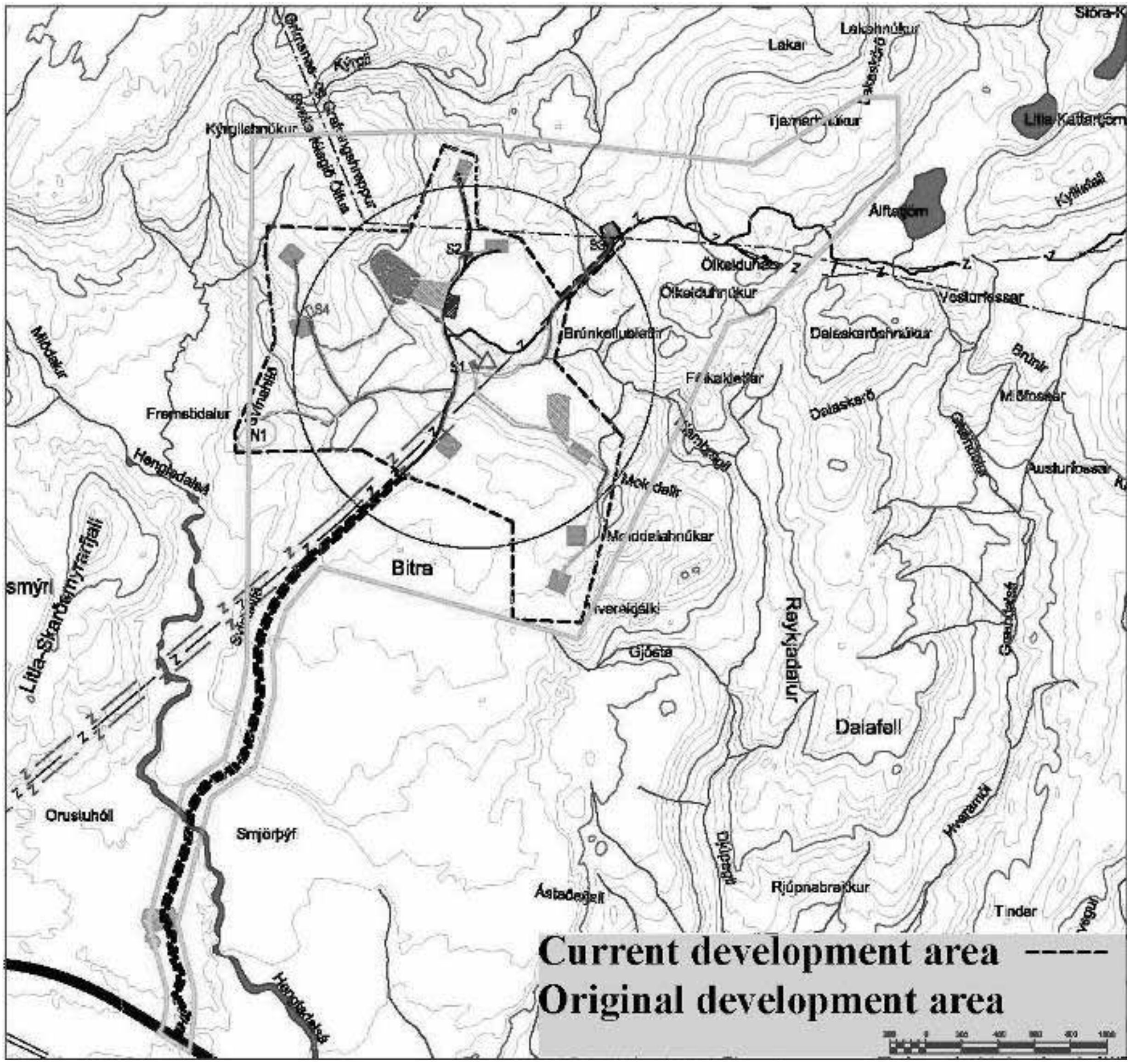


Fig. 8. Bitra’s development area.

Three research boreholes have been drilled in the area. Size of the power plant was estimated from information gathered from those boreholes and results from a model of the geothermal area [7]. Estimated capacity of power plant in Bitra is 135 MW_{el}.

5.3 Power plant at Hverahlíð

The developments are is located about 3 km southeast of Hellisheiði power plant. The development area of the power plant was reduced from its original size because of environmental reason (Fig. 9). Like in Bitra the reduction of the development area and OR’s environmental policy will result in minimal effect of the Hverahlíð power plant on its surroundings [6].

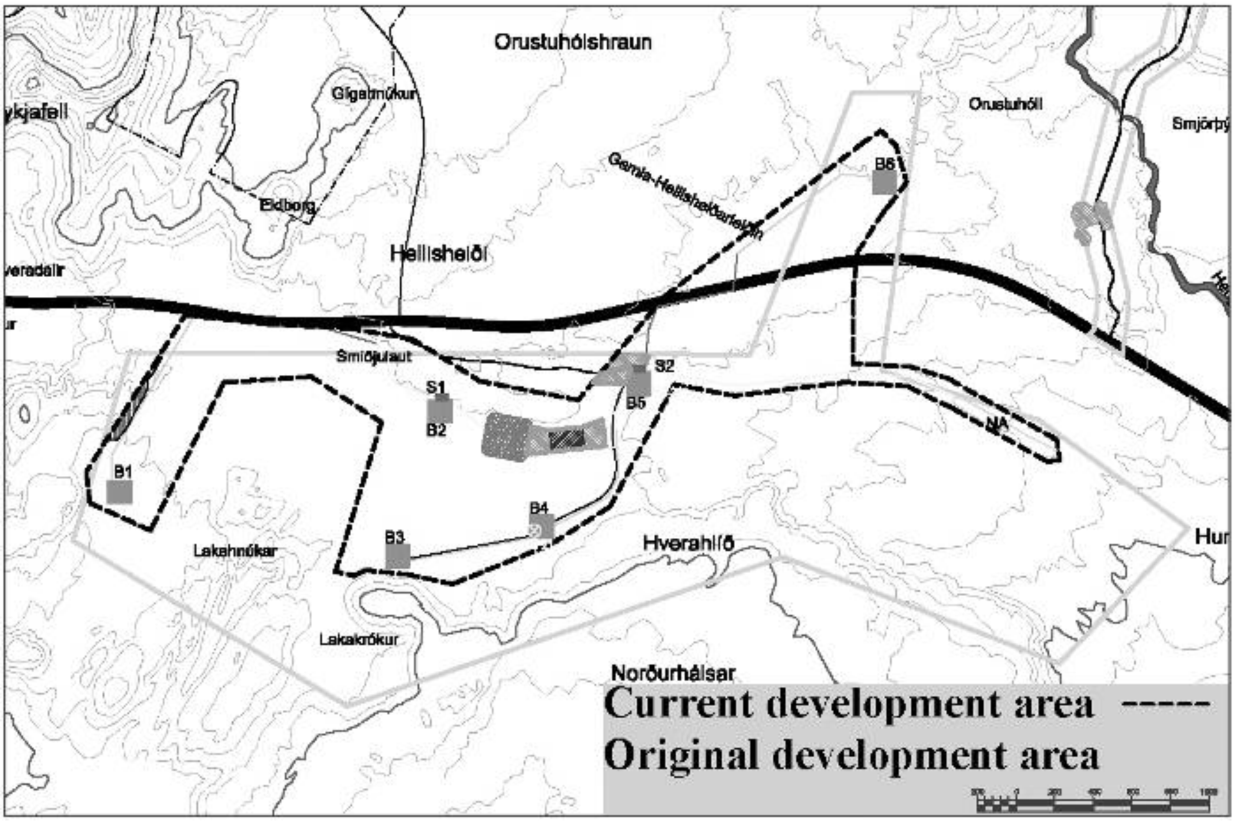


Fig. 9. Hverahlíð’s development area.

Three research boreholes have been drilled in the area. Size of the power plant was estimated from information gathered from those boreholes and results from a model of the geothermal area [7]. Estimated capacity of power plant in that area is 90 MW_{el}.

5.4 Construction plan

If EIA’s for the new power plants will get an approval from the Planning Agency and approval for operation from the local municipality; Ölfuss, work on site can start before the middle of 2008. First stage of each power plant, 90 MW_{el} in Bitra and also in Hverahlíð, can then start operation in 2011.

6. RESEARCH PROJECTS IN THE HENGILL AREA

With more knowledge of the Hengill geothermal area accumulated through running the Nesjavellir and Hellisheiði power plants and research drilling new opportunities arises which can be utilized both in future power plants in the area and in other projects.

6.1 New research areas in the Hengill area

While looking for a suitable discharge area for Hellisheiði power plant a research boreholes were drilled south of the Hellisheiði power plant. It was thought that there should be the edge of the defined geothermal area. Results from the research drilling showed that the geothermal area extends father south. Because of this it was decided to research those areas that are called Gráuhnúkar and Meitill. OR has already applied for a research license in those areas. If research drilling will give positive results it will be possible to extend the operation area of Hellisheiði power plant to those sites or built up a new smaller power plants in those areas. Ether way an EIA will be necessary.

OR plans to start research drilling in Gráuhnúkar and Meitill next year.

6.2 Carb-Fix. Nature Imitated in Permanent CO_2 Storage Project

In fall 2007 a project was launched with the aim at storing CO_2 in Iceland's lavas by injecting the greenhouse gas into basaltic bedrock where it literally turns to stone. Carbon dioxide turning into calcite is a well-known natural process in volcanic areas and now the scientists of the University of Iceland, Columbia University N.Y. and the CNRS in Toulouse, France are developing methods to imitate and speed up this transformation of the gas that is the prevalent contributor to global warming.

Injecting CO_2 at carefully selected geological sites with large potential storage capacity can be a long lasting and environmentally benign storage solution. To date CO_2 is stored as gas in association with major gas production facilities. The uniqueness of the Icelandic project is that whereas other projects store CO_2 mainly in a gas form, where it could potentially leak back into the atmosphere, the current project seeks to store CO_2 by creating calcite in the subsurface. Calcite, a major component of limestone, is a common and stable mineral in the Earth is known to persist for tens of millions of years or more.

In the project at Hengill area a mixture of water and steam is harnessed from 2000 m deep wells at Hellisheidi power plant. The steam contains geothermal gases, i.e. CO_2. It is planned to dissolve the CO_2 from the plant in water at elevated pressure and then inject it through wells down to 400-800 m, just outside the boundary of the geothermal system

It is estimated that the project will take three to five years and its scheduled to start a full scale CO_2 injecting in the end of 2008 or beginning of 2009.

6.3 IDDP, The Icelandic Deep Drilling Project

The Icelandic Deep Drilling Project (IDDP) is a consortium of three, Icelandic energy companies preparing to drill a 4-5 km deep borehole into a high-temperature hydrothermal system. The goal is to reach 400-600°C supercritical hydrous fluid at a rifted plate margin on a mid-ocean ridge.

The main purpose of the IDDP is to find out if it's economically feasible to extract energy and chemicals out of hydrothermal systems at supercritical conditions. Potential benefits of the IDDP include increased power output per well, perhaps by and order in magnitude, and production of higher-level, high-pressure, high-temperature steam. Also, the development of an environmentally friendly energy source below currently producing energy fields. In addition, the extended lifetime of the exploited geothermal reservoirs. The IDDP consortium is composed of OR, Hitaveita Suðurnesja, Landsvirkjun and the National Energy Authority of Iceland.

7. CONCLUSION

OR is planning to produce at least 600 MW_{el} and 433 MW_{th} by the end of 2011 in it's power plants in the Hengill area.

OR places its main emphasis on the quality of its goods and services. The company focuses on quality, reliability and profitability to ensure successful operations. OR realizes the importance of protecting the country's natural resources and ensuring, as far as possible, their sustainable utilization.

8. ACKNOWLEDGMENT

The authors acknowledge the contributions of Hólmfríður Sigurðardóttir for her help with the Carb-Fix section and María S. Guðjónsdóttir and Óskar Sigurðsson for their help with translation

and drawings.

9. REFERENCES

[1] Iðnaðarráðuneytið, 1994, *Innlendar orkulindir til vinnslu raforku*. Iðnaðarráðuneytið.

[2] Orkuveita Reykjavíkur, 2003, *Nesjavellir power plant*. Orkuveita Reykjavíkur

[3] VGK, 2003. Virkjun á Hellisheiði, Rafstöð allt að 120 MW, Varmastöð allt að 400 MW. Mat á umhverfisáhrifum. VGK for Orkuveita Reykjavíkur.

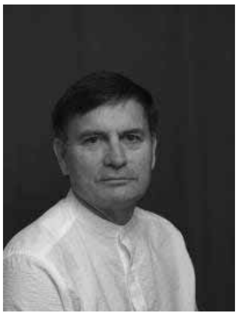
[4] VGK, 2005. *Stækkun Hellisheiðarvirkjunar, Mat á umhverfisáhrifum*. VGK for Orkuveita Reykjavíkur.G. O. Young, "Synthetic structure of industrial plastics," in *Plastics*, 2nd ed., vol. 3, J. Peters, Ed. New York: McGraw-Hill, 1964, pp. 15-64.

[5] VSÓ, 2007. Bitruvirkjun, allt að 135 MW_e jarðvarmavirkjun. Frummatsskýrsla. VSÓ for Orkuveita Reykjavíkur.

[6] VSÓ, 2007. Hverahlíðarvirkjun, allt að 90 MW_e jarðvarmavirkjun. Frummatsskýrsla. VSÓ for Orkuveita Reykjavíkur.

[7] Grímur Björnsson, 2007. Endurskoðað hugmyndalíkan af jarðhiakerfum í Hengli og einfalt mat á vinnslugetu nýrra borsvæða. Orkuveita Reykjavíkur.

10. BIOGRAPHIES



Ingólfur Hrólfsson holds an MSc (1972) from the NTH, Trondheim. Ingólfur worked as an engineer for Gatnamálastjóri in Reykjavik 1972, engineer for Verkfræðistofa Suðurlands from 1974 to 1980 and Director of the Hot Water Utility in Akranes and Borgarfjörður from 1980 to 1996. From 1996 he has worked for Hitaveita Reykjavíkur, now Orkuveita Reykjavíkur. Ingólfur is Head of New Power Projects.

Sigurgeir Björn Geirsson holds an MSc (2003) from the University of Iceland, Faculty of Engineering. Sigurgeir has worked with Orkuveita Reykajvíkur since 2003. He has been Manager of Design for New Power Projects since 2007.

Received 11 February 2008-
Paper 08GM0965

6. The Economic Rent in Hydro and Geothermal Resources in Iceland with Reference to International Energy Markets

Egill Benedikt Hreinsson, University of Iceland

Abstract**:** In this paper the concept of Economic Rent (ER) is reviewed and applied to the virtually emission-free renewable energy resources of Iceland. In particular, a case study is presented with experimental test data from the Icelandic hydro and geothermal system. A calculation is presented based on prices in the domestic and an international market as well as cost assumptions. The importance of the ER concept is of particular interest in a case where the electric power system utilizes renewable energy resources to the greatest extent of almost any country in the world. For this reason the Iceland energy situation should be of special interest, where no fossil fuel resources are available and where fuel-based electricity generation is virtually non-existent. The results of the paper include a case study suggesting the economic significance of renewable natural energy resources in the form of ER. A pilot numerical example is presented to lead the way for further appraisal of the economic value of these resources with a more developed data set and cost assumptions.

Index terms**:** Economic rent, Renewable energy resources

1. INTRODUCTION

Iceland enjoys an abundance of indigenous renewable energy resources in hydroelectricity and geothermal energy. In a country with no fossil fuel resources, fuel-based electricity generation is virtually non-existent. In fact, the electric power system already utilizes renewable energy resources to the greatest extent of almost any country in the world.

Furthermore, Iceland's power system is presently enjoying one of the highest growth rates of any country. The growth has recently come primarily from new aluminum production. This utilization has for a long time been considered the most important means of realizing the economic rent of these resources by "exporting energy resources in the form of aluminum". However, the future growth in generation may come from other types of extended demand, such as hydrogen production, information technology based loads or direct export or exchange of renewable electrical energy with neighboring countries through a HVDC submarine cable.

Iceland's energy resources have in recent decades played a very important role in the growth of the economy on the whole and will undoubtedly continue to do so. In this paper we focus on the *value* of these resources in the form of *economic rent* (ER) [1] and in this paper, we review the evolution of the important concept ER as applicable to a renewable hydro and geothermal based power system [2-11].

In the next (second) section of this paper, the concept of ER is reviewed and a discussion presented on the use of this concept to estimate the economic value of renewable energy resources. What is economic rent (ER)? Basically, in simplified terms, it is what is left of the market value of the resources, when the cost of exploiting them, transforming them to a commodity and bringing them to the market, has been deducted.

In the third section of the paper, the electric power and energy resource situation in Iceland is reviewed, both in terms of hydroelectric and geothermal energy and other resources. In addition, the possibilities of imports/exports and other backstop supplies are discussed. These could serve as an economic reference for calculating the economic rent. Furthermore, the market situation is reviewed with the present deregulation process. The historical public policy of utilizing the resources for energy intensive industry is discussed. The new paradigm emerging with the deregulation and market liberalization calls for new concepts and new thinking.

The concept ER is particularly applicable in this situation with an emerging electricity market in a totally renewable system, where a monopoly was previously the case. The possibilities of exporting to a foreign market make this concept even more interesting. Therefore these possibilities are discussed with the possible associated price development in these foreign electricity markets. In particular, the situation in England and Scotland is noted along with the economic indicators and key quantities associated with a High Voltage Direct Current (HVDC) submarine interconnection from Iceland to neighboring countries.

In the fourth section, a numerical case study for the Iceland case is presented with and example calculation estimating economic rent of individual projects. The amount of the resource available at each site and in each region is presented with the associated cost estimates and unit cost calculations. This is based on the methodology as discussed in the previous sections. The results are set forth in tables. These calculations are based on an experimental data set of hydro and geothermal projects from the on-going Master Plan (MP) [19]. Since a comprehensive data set, or a list of available projects, is yet to be developed within the MP or by other means, we use data from the experimental evaluation for both hydro and geothermal projects from phase 1 of the MP. It should be noted that the numerical example in the case study is based on imperfect data where, for instance, mutually exclusive projects are present and some cost estimates are grossly simplified.

Finally in the last section of the paper, further conclusions and discussions of results and suggestions for further work are set forth.

2. ECONOMIC RENT

Economic rent (ER) is also called *scarcity rent* or *resource rent* depending on the circumstances. It is a well-known concept from the history of economics, [1] and is derived originally from the valuation of agricultural land near cities with the associated distance and cost to bring the produce to the market.

The ER concept applies to any natural resource, such as mines and minerals, land and energy resources based on specific geographical locations and conditions. Therefore it is readily applicable to hydroelectric and geothermal energy resources. Basically, it is the difference between the market value of a specific resource based commodity and the cost of exploiting it. Therefore, in this sense, it represents the net value of the given resource.

A very similar concept is the *water rights* in the case of hydroelectric energy or the *geothermal concessions* in the case of geothermal power for the owners of the resource. These basically are the legal rights to build hydro- or geothermal projects at a specific project site and linking them to a market. In the case of Iceland the owners of the resource are the landowner of the river valley or geothermal areas.

Although one can say that ER is most meaningful when there is a developed market for the product, ER can still be calculated in the absence of such a market. Then the net value of a specific resource (ER) can be estimated as the extra cost of replacing the resource with an alternative or back-up resource. Therefore the ER for a specific mine or an oil field or a hydroelectric site, for instance, can be calculated even without a market for the product, by calculating the difference between the cost of the back-stop alternative supply needed as a substitute for the given resource and the cost of the given resource. The ER, then, for instance, is the difference in cost of having and not having a specific hydro site and represents the extra value of the availability of a specific hydro project location.

As is well known, renewable energy resources differ significantly in cost and characteristics across the possible sites for exploitation. For instance, some hydroelectric sites may be very favorable due to geographical and geological conditions. Other sites may be very costly because they need considerable earth movements, dam building etc.

Figure 1 shows a typical profile for the unit cost of hydro or geothermal project sites, where individual projects have been lined up with an increasing cost, represented by the thick, step-wise increasing line. This sequencing of project may represent the most economical sequence for exploiting the resource for a generating company in a monopoly environment responsible for exploiting the resources. However in a market based trading environment, the individual projects may represent licenses for different generating companies.

In the old monopoly environment, ER had a somewhat vague interpretation, because tariffs to the public were set according to cost and often controlled by the authorities. In a monopolistic power industry, based on renewable resources, water or geothermal steam was considered "free from nature" and contributed to the benefit to the customers, represented by the public service of the utilities of the day. Therefore in this case, the ER was passed on to customer, even for individual projects, or based on average cost for a range of projects with different costs as shown in

Figure 1, but belonging to the same utility company. Therefore, in the monopoly case of expensive alternative fuel based resources and assuming no market, the ER would have had high value passed on to the customers and became their benefit. In the case of Iceland in the pre-deregulation era, therefore, Icelandic energy users were blessed with extensive benefit (ER) of hydro and geothermal, because otherwise to satisfy demand would have called for the import of expensive fossil fuel as a back-up resource.

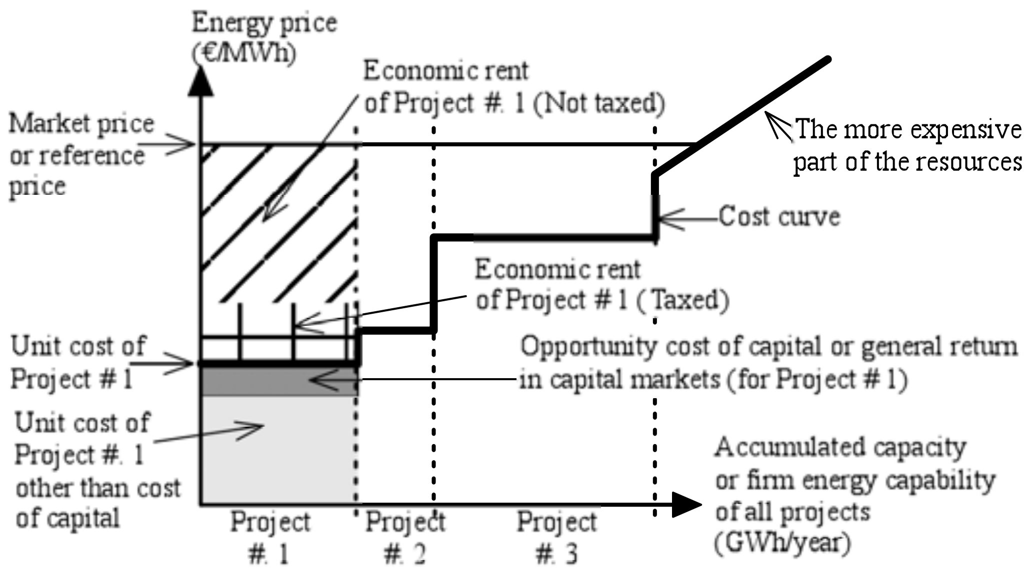


Figure 1: Economic rent (ER) for a sequence of hydro or geothermal projects

The ER representation of Figure 1 will now be examined more closely.

First, for a project sequence with increasing unit energy cost, ER can be visualized graphically in Figure 1. An example with 3 projects is shown and their increasing unit cost (thick, stepwise increasing cost curve). In addition the back-up supply, or alternatively the more expensive part of the resources, is assumed to have an ever-increasing cost, as indicated by the upward line at the far right.

Secondly the market price is shown as a horizontal line. This can also represent a reference price of the alternative resources, assumed without size limit, in which case both curves, in principle, would continue horizontally to the right at the intersection.

For each project, the vertical difference between the market price curve and the cost curve represents the economic rent (ER) per unit of energy output. The hatched area, therefore, represents the total ER. In both cases these can be discounted values or annual values, for instance. The ER for project #1 is shown by the hatched area, while the overall ER for all projects is the total area between the curves.

The ER can be decomposed into a non-taxed part and a taxed part. An example where the ER is taxed is the case of Norway, where the value of the output at the spot price minus the cost, as derived from accounting, is taxed for each year.

It should be noted that the ER represents a benefit to the owner of the resource *in excess* of what is generally available for the investment in capital markets. Therefore, in

Figure 1 the cost below the thick line includes an opportunity financial cost as would otherwise be available generally in financial markets.

3. THE ICELANDIC ELECTRICITY SYSTEM AND MARKET SITUATION

We now discuss the renewable resources in Iceland and the electricity market development with the deregulation process. The system has been previously described by this author and elsewhere [12][13][14].

Iceland has only utilized a limited fraction of the renewable energy resources. Figure 2 shows the principal breakdown in 2005 and 2010:

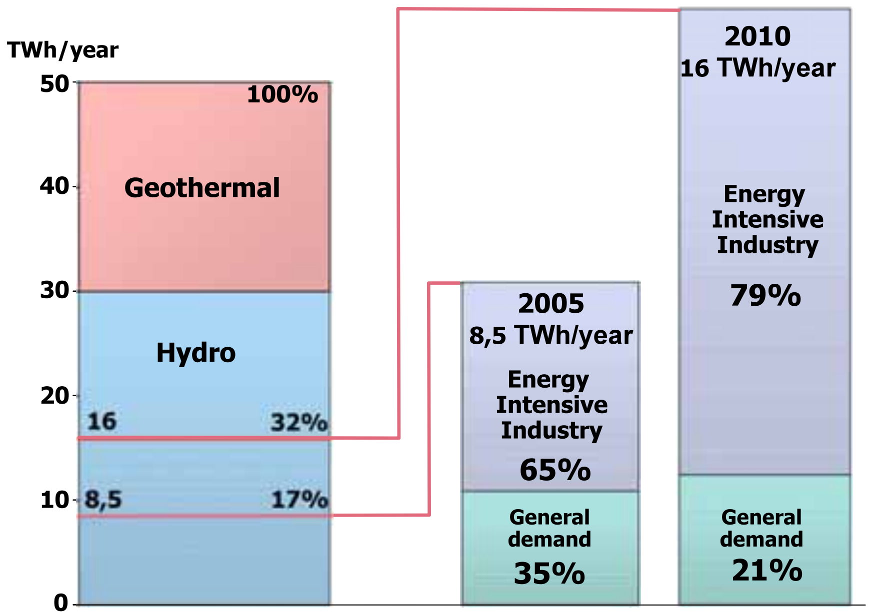


Figure 2: Total resource capacity and estimated electricity generation 2005 and 2010

The figure shows that only about 17% of the estimated resources for electricity generation were utilized by 2005 and an estimated of 32% will be utilized by 2010. The total extent of the resources is estimated to be 30 TWh/year of hydro and 20 TWh/year of geothermal. This constitutes the bulk of the renewable energy resources known and available in Iceland for electricity generation. These resources are scattered among possible sites, as will be described in section 4 with a numerical example.

The history will be briefly reviewed. Hydro development basically started in 1970 in SW Iceland with the Thjorsa cascade of Burfell (230 MW), Sigalda (150 MW), Hrauneyjar (210 MW), Vatnsfell (90 MW) and Sultartangi (120 MW). In 1991 Blanda (150 MW) in the North was added and Kárahnjúkar in the East (650 MW) in 2007. The geothermal part started with Krafla (60 MW) in the 70's, Nesjavellir (90 MW) and Svartsengi (17 MW). Presently under construction are Reykjanes (100 MW) and Hellisheidi (120 MW).

Around 80% of the total electricity demand will in 2008 be from power intensive industry. A seasonal reservoir, Thorisvatn is located above the SW cascade. Blanda and Kárahnjúkar have their own reservoirs and all are storing water from summer with glacial melting to winter with heavy load and low inflow.

Until 2003 the power sector was characterized by a monopoly structure. The National Power Co (NPC) owned and operated more than 90% of the hydro capacity and the bulk transmission system. RARIK, the state rural utility, owned minor hydro and the rural distribution system. Reykjavik Energy (RE) had electricity and geothermal district heating and cold-water distribution in Reykjavik and suburbs, while Hitaveita Suðurnesja (HS) owned geothermal plants and distributed electricity and geothermal water for space heating. Other smaller utilities have also operated.

Iceland was bound by the EU Directive of 1996 to deregulate its power system. The Electricity act was passed in 2003, where the utilities were required to unbundle their operations. In light of the special resource mix and market size, it was important to reform carefully and gradually. However, as of 2008 there is still no spot market, although there has been a pilot balancing market.

To obtain a reference price for the calculation of the ER, one has to make an estimate of available markets and their prices both domestic and international. For a connection to an international market an HVDC link is necessary and will be discussed below as a future possibility. To estimate the value of the ER, therefore, we have basically the following alternatives for the market price reference:

1. The domestic market
   a. General residential demand and balancing market
   b. Demand from energy intensive industry
2. International markets - linked by a possible HVDC cable. These could be:
   a. United Kingdom
   b. Nordic Electricity markets
   c. Continental European markets
3. Reference value of alternative resources.

For each of these markets, (except the Nordic and European) we estimate the most likely current market prices. Table 1 shows such estimates with price ranges. The domestic market is limited in size, given the size of the Icelandic economy. Although the larger projects are basically too large for this market, its prices can still serve as a reference. It may in some cases be difficult to get and estimate for the domestic market. However, the estimates in Table 1, are from [15], [16] and [17]. From [17] the prices available in the domestic market range from 2.10-2.90 ISK/kWh, which is equivalent to about 30-42 US$/MWh at the present given rate of exchange (69.5 ISK/US$).

Table 1
A market reference prices for the case study

	Low	High	**Aver-age**	Low	High	**Aver-age**
Domestic markets:	Price: US$/MWh			Price: ISK/kWh		
New energy intensive industry contracts	30.2	33.1	**31.7**	2.10	2.30	**2.20**
Residential and Domestic bilateral contracts	37.4	41.7	**39.6**	2.60	2.90	**2.75**
Pilot Balancing market	34.5	36.0	**35.3**	2.40	2.50	**2.45**
International market:						
Market price UK Electricity Market (in UK)	67.6	75.5	71.6	4.70	5.25	4.98
Transmission cost to a UK market	21.6	36.0	28.8	1.50	2.50	2.00
Market price UK Market (incl transmission)	46.0	39.6	**42.8**	3.20	2.75	**2.98**

To use any international market as a reference, we assume a link to that market with a hypothetical HVDC submarine cable connection. Such an HVDC cable has been studied on several occasions [18]. Such studies have shown that such cable is technically feasible. However the economics of such a cable will depend of prices available in the market. Prior cost estimates indicate that the total cost including investment and operations cost is approximately the same as for the large economical hydro projects, such as the Kárahnjúkar project. Therefore, as shown in

Table 1, we assume a transmission cost for an Iceland-UK connection to be in the range of 22-36 US$/MWh. Of course this is a very preliminary figure for the sake of a case study and we make reservations regarding several assumptions related to this cost figure.

For international markets, the figures in Table 1 show an estimate from the UK market of about 67 to 72 US$/kWh [15], [16], based on contract for a UK delivery. Deducting the transmission cost gives a reference price estimate based on an Iceland delivery of 40-46 US$/MWh. Discussions and further reservations regarding this assumption are presented in section 5.

4. CASE STUDY: ECONOMIC RENT AND A NUMERICAL EXAMPLE

In this section we will now present a case study involving a numerical example with a set of projects with their cost and firm energy estimates. These are derived from the Iceland experimental evaluation in the ongoing Master Plan (MP) a Government project for the expansion and preservation of natural resources and the renewable energy resources [12], [19].

Table 5 in the Appendix shows the list of projects with their characteristic data from [19]. The table shows from left to right the type of project, an index number and name. The project indexed “x” is a summation of several geothermal projects, all with the same estimated unit cost and firm energy according to the MP. Then the firm energy production capability is listed with investment cost. The total capacity of all projects is 39.8 TWh/year with 21.8 in hydro and 18 in Geothermal. After the investment cost is shown, the operations cost and total cost is listed in the table.

We make a reservation about this data set as it is only derived from the experimental evaluation results in the MP/phase 1 [19]. It must be stated that there are several mutually exclusive alternatives in this data set, or repetitions, which would have to be excluded in a realistic sequence. Nevertheless, the total in the table is the same order of magnitude as shown in Figure 2 or about 40 TWh/year as compared to 50 TWh/year in Figure 2. Furthermore, in this numerical example the data set serves the purpose to show what an ER evaluation could look like. Therefore we make the reservation and point out the fact that these are only experimental data, waiting to be completed with the further development evaluation of the on-going MP/phase 2 etc.

Further assumptions involve the market price or the reference price of 28 US$/MWh (2 ISK/kWh) assuming the currency rate of exchange of 69.5 ISK/US$. 3 alternatives for the reference price are shown in the following tables, i.e. 28,78 US$/MWh (2.00 ISK/kWh) in Table 2, 35.97 US$/MWh (2.50 ISK/kWh) in Table 3 and 43.17 US$/MWh (3.00 ISK/kWh) in Table 4. The tables show ER in US$/MWh and the annual ER in Million US$/year. In addition, on the right in the tables is shown the discounted value of the ER for the data set.

In all cases the planning horizon is 40 years and the operations cost for the hydro is assumed 2% of the investment cost per year while the corresponding figure for the geothermal projects is 3%. The annual discount rate (interest rate) is assumed with 3 alternatives, 5%, 6% or 7% per year as shown in the tables. Three different results from the ER estimate are shown in the 3 tables (Table 2, Table 3 and Table 4) based on different assumptions regarding the reference or market price. For a discussion of this reference price, see previous section 3.

Table 2
An experimental data (Reference price 28.8 US$/MWh or 2.00 ISK/kWh)

Project No.	Resource Rent per MWh (US$/MWh) with interest			Annual Resource Rent (Million US$/year)			Discounted value of resource rent: Million US$			Discounted value of resource rent: % of Investm cost		
	5%	6%	7%	5%	6%	7%	5%	6%	7%	5%	6%	7%
7	8,05	5,89	3,62	32,21	23,55	14,49	552,7	354,3	193,2	52%	33%	18%
8	6,25	3,90	1,44	29,19	18,19	6,71	500,9	273,8	89,4	37%	20%	7%
9	7,49	5,26	2,94	10,41	7,32	4,09	178,6	110,1	54,5	47%	29%	14%
14	19,54	18,58	17,57	8,79	8,36	7,91	150,9	125,8	105,4	284%	237%	199%
30	7,56	5,60	3,54	6,35	4,70	2,98	109,0	70,8	39,7	54%	35%	20%
10	5,69	3,27	0,75	5,14	2,96	0,68	88,2	44,5	9,1	33%	17%	3%
43	6,29	4,21	2,03	5,29	3,54	1,71	90,7	53,2	22,8	42%	25%	11%
52	6,17	4,07	1,88	5,18	3,42	1,58	88,9	51,5	21,1	41%	24%	10%
15	10,42	8,50	6,49	6,77	5,52	4,22	116,2	83,1	56,3	76%	55%	37%
17	3,21	0,54	0,00	3,21	0,54	0,00	55,1	8,1	0,0	17%	2%	0%
18	2,76	0,04	0,00	2,81	0,04	0,00	48,2	0,6	0,0	14%	0%	0%
x	4,64	2,41	0,07	66,31	34,36	0,99	1137,8	517,0	13,2	29%	13%	0%
19	2,65	0,00	0,00	2,43	0,00	0,00	41,8	0,0	0,0	14%	0%	0%
5	4,90	2,40	0,00	2,82	1,38	0,00	48,3	20,8	0,0	28%	12%	0%
50	5,53	3,38	1,13	3,10	1,89	0,63	53,2	28,5	8,4	36%	19%	6%
1	1,18	0,00	0,00	1,24	0,00	0,00	21,2	0,0	0,0	6%	0%	0%
39	13,66	12,26	10,80	2,87	2,57	2,27	49,2	38,7	30,2	137%	108%	84%
2	0,62	0,00	0,00	0,80	0,00	0,00	13,7	0,0	0,0	3%	0%	0%
16	2,65	0,00	0,00	1,67	0,00	0,00	28,6	0,0	0,0	14%	0%	0%
51	9,34	7,54	5,66	2,62	2,11	1,58	44,9	31,8	21,1	73%	52%	34%
6	2,53	0,00	0,00	1,57	0,00	0,00	26,9	0,0	0,0	13%	0%	0%
13	1,30	0,00	0,00	1,11	0,00	0,00	19,0	0,0	0,0	6%	0%	0%
11	4,00	1,41	0,00	1,75	0,62	0,00	30,0	9,3	0,0	22%	7%	0%
12	2,08	0,00	0,00	1,53	0,00	0,00	26,3	0,0	0,0	10%	0%	0%
31	15,19	13,93	12,61	2,13	1,95	1,77	36,5	29,3	23,5	169%	136%	109%
3	1,30	0,00	0,00	0,25	0,00	0,00	4,2	0,0	0,0	6%	0%	0%
4	0,00	0,00	0,00	0,00	0,00	0,00	0,0	0,0	0,0	0%	0%	0%
HYDRO	**5,22**	**3,14**	**1,75**	**114**	**68**	**38**	**1.951**	**1.030**	**508**	**29%**	**16%**	**8%**
GEOTH	**5,22**	**3,03**	**0,75**	**94**	**55**	**14**	**1.610**	**821**	**180**	**34%**	**17%**	**4%**
TOTAL	**5,22**	**3,09**	**1,30**	**208**	**123**	**52**	**3.561**	**1.851**	**688**	**31%**	**16%**	**6%**

In Table 2, with a reference or market price of 28,78 US$/MWh as an example, the 2nd project from the top (project #8) has, for 5% interest rate, an ER of 29,19 Million US$/year or a discounted value of 500.9 Million US$ and the total ER of all the hydro resources in the table 1951 Million US$ and for total hydro and geothermal resources we get 3.561 Billion US$.

However in Table 3, with the reference price increased to 35.97 US$/MWh, we see that the corresponding figures have changed to 1077 million US$ and the total ER of all the hydro resources in the table to 4.59 Billion US$ and for total hydro and geothermal resources we get 8.421 Billion US$.

Finally for Table 4, with the reference price increased to 43.17 US$/MWh, we see that the figures have changed to 1654 million US$/MWh for project #8 and the total ER of all the hydro resources in the table has changed to 7.23 Billion US$ and for total hydro and geothermal resources we get 13.28 Billion US$.

Table 3
An experimental data (Reference price 35.9 US$/MWh or 2.50 ISK/kWh)

Project	Resource Rent per MWh			Annual Resource Rent			Discounted value of resource rent					
No.	(US$/MWh) with interest			(Million US$/year)			Million US$			% of Investm cost		
	5%	6%	7%	5%	6%	7%	**5%**	**6%**	**7%**	**5%**	**6%**	**7%**
7	15.25	13.08	10.82	60.99	52.32	43.27	**1046.5**	**787.3**	**576.9**	99%	74%	54%
8	13.45	11.09	8.63	62.79	51.79	40.30	**1077.4**	**779.3**	**537.3**	80%	58%	40%
9	14.68	12.46	10.13	20.41	17.32	14.09	**350.2**	**260.6**	**187.8**	93%	69%	50%
14	26.74	25.77	24.76	12.03	11.60	11.14	**206.4**	**174.5**	**148.6**	389%	329%	280%
30	14.76	12.79	10.74	12.40	10.75	9.02	**212.7**	**161.7**	**120.3**	105%	80%	60%
10	12.88	10.47	7.95	11.65	9.46	7.18	**199.8**	**142.4**	**95.8**	75%	53%	36%
43	13.49	11.40	9.23	11.33	9.58	7.75	**194.4**	**144.1**	**103.3**	91%	67%	48%
52	13.36	11.27	9.08	11.22	9.46	7.62	**192.6**	**142.4**	**101.6**	90%	66%	47%
15	17.61	15.69	13.69	11.45	10.20	8.90	**196.4**	**153.5**	**118.6**	129%	101%	78%
17	10.40	7.73	4.94	10.41	7.74	4.94	**178.7**	**116.4**	**65.9**	55%	36%	20%
18	9.95	7.23	4.39	10.14	7.37	4.48	**174.0**	**110.9**	**59.7**	51%	33%	18%
x	11.84	9.60	7.26	169.04	137.09	103.73	**2900.6**	**2062.8**	**1382.8**	74%	53%	35%
19	9.84	7.11	4.26	9.05	6.54	3.92	**155.4**	**98.4**	**52.2**	51%	32%	17%
5	12.09	9.60	6.99	6.95	5.52	4.02	**119.3**	**83.0**	**53.6**	68%	47%	31%
50	12.73	10.57	8.32	7.13	5.92	4.66	**122.3**	**89.1**	**62.1**	83%	60%	42%
1	8.38	5.49	2.48	8.76	5.74	2.59	**150.3**	**86.4**	**34.6**	41%	23%	9%
39	20.86	19.45	17.99	4.38	4.09	3.78	**75.2**	**61.5**	**50.4**	209%	171%	140%
2	7.81	4.87	1.80	10.08	6.28	2.32	**173.0**	**94.5**	**30.9**	37%	20%	7%
16	9.84	7.11	4.26	6.20	4.48	2.68	**106.4**	**67.4**	**35.7**	51%	32%	17%
51	16.54	14.74	12.85	4.63	4.13	3.60	**79.5**	**62.1**	**48.0**	129%	101%	78%
6	9.73	6.98	4.12	6.01	4.32	2.55	**103.2**	**64.9**	**33.9**	50%	31%	16%
13	8.49	5.62	2.62	7.26	4.80	2.24	**124.5**	**72.3**	**29.8**	41%	24%	10%
11	11.19	8.60	5.90	4.90	3.77	2.58	**84.1**	**56.7**	**34.4**	61%	41%	25%
12	9.28	6.49	3.57	6.82	4.77	2.63	**117.0**	**71.7**	**35.0**	47%	29%	14%
31	22.38	21.12	19.80	3.13	2.96	2.77	**53.8**	**44.5**	**37.0**	249%	206%	171%
3	8.49	5.62	2.62	1.61	1.07	0.50	**27.7**	**16.1**	**6.6**	41%	24%	10%
4	0.00	0.00	0.00	0.00	0.00	0.00	**0.0**	**0.0**	**0.0**	0%	0%	0%
HYDRO	**12.28**	**9.87**	**7.36**	**268**	**215**	**160**	4,590	3,236	2,137	**69%**	**49%**	**32%**
GEOTH	**12.41**	**10.23**	**7.95**	**223**	**184**	**143**	3,831	2,768	1,906	**80%**	**58%**	**40%**
TOTAL	**12.34**	**10.03**	**7.62**	**491**	**399**	**303**	8,421	6,004	4,043	**74%**	**52%**	**35%**

Table 4
An experimental data (Reference price 43.2 US$/MWh or 3.00 ISK/kWh)

Project	Resource Rent per MWh			Annual Resource Rent			Discounted value of resource rent					
No.	(US$/MWh) with interest			(Million US$/year)			Million US$			% of Investm cost		
	5%	6%	7%	5%	6%	7%	**5%**	**6%**	**7%**	**5%**	**6%**	**7%**
7	22.44	20.27	18.01	89.77	81.10	72.05	**1540.3**	**1220.3**	**960.5**	145%	115%	91%
8	20.64	18.28	15.82	96.39	85.39	73.90	**1653.9**	**1284.8**	**985.2**	123%	96%	73%
9	21.88	19.65	17.33	30.41	27.32	24.09	**521.8**	**411.0**	**321.1**	138%	109%	85%
14	33.93	32.96	31.96	15.27	14.83	14.38	**262.0**	**223.2**	**191.7**	493%	420%	361%
30	21.95	19.99	17.93	18.44	16.79	15.06	**316.4**	**252.6**	**200.8**	157%	125%	99%
10	20.08	17.66	15.14	18.15	15.97	13.69	**311.4**	**240.2**	**182.5**	117%	90%	68%
43	20.68	18.60	16.42	17.37	15.62	13.79	**298.1**	**235.1**	**183.9**	139%	110%	86%
52	20.56	18.46	16.27	17.27	15.51	13.67	**296.3**	**233.3**	**182.2**	138%	108%	85%
15	24.81	22.89	20.88	16.12	14.88	13.57	**276.7**	**223.8**	**181.0**	181%	147%	119%
17	17.60	14.93	12.13	17.62	14.94	12.15	**302.3**	**224.8**	**161.9**	92%	69%	50%
18	17.15	14.43	11.59	17.47	14.70	11.81	**299.8**	**221.2**	**157.4**	89%	65%	46%
x	19.03	16.79	14.46	271.78	239.83	206.46	**4663.4**	**3608.5**	**2752.5**	119%	92%	71%
19	17.04	14.30	11.45	15.67	13.16	10.53	**268.9**	**198.0**	**140.4**	88%	64%	46%
5	19.29	16.79	14.18	11.09	9.66	8.16	**190.3**	**145.3**	**108.7**	108%	83%	62%
50	19.92	17.77	15.52	11.16	9.95	8.69	**191.4**	**149.7**	**115.8**	130%	102%	79%
1	15.57	12.69	9.67	16.29	13.27	10.12	**279.5**	**199.7**	**134.9**	76%	54%	37%
39	28.05	26.65	25.19	5.89	5.60	5.29	**101.1**	**84.2**	**70.5**	281%	234%	196%
2	15.01	12.06	8.99	19.36	15.56	11.60	**332.2**	**234.2**	**154.6**	72%	50%	33%
16	17.04	14.30	11.45	10.73	9.01	7.21	**184.2**	**135.6**	**96.2**	88%	64%	46%
51	23.73	21.93	20.05	6.64	6.14	5.61	**114.0**	**92.4**	**74.8**	185%	150%	121%
6	16.92	14.18	11.31	10.46	8.76	6.99	**179.5**	**131.8**	**93.2**	87%	64%	45%
13	15.68	12.81	9.81	13.41	10.95	8.39	**230.1**	**164.8**	**111.8**	77%	55%	37%
11	18.39	15.80	13.09	8.05	6.92	5.73	**138.2**	**104.1**	**76.4**	100%	75%	55%
12	16.47	13.68	10.77	12.11	10.06	7.91	**207.7**	**151.3**	**105.5**	83%	60%	42%
31	29.57	28.31	27.00	4.14	3.96	3.78	**71.0**	**59.6**	**50.4**	330%	277%	234%
3	15.68	12.81	9.81	2.98	2.43	1.86	**51.1**	**36.6**	**24.8**	77%	55%	37%
4	0.00	0.00	0.00	0.00	0.00	0.00	**0.0**	**0.0**	**0.0**	0%	0%	0%
HYDRO	**19.34**	**16.93**	**14.42**	**421**	**369**	**314**	7,230	5,551	4,188	**109%**	**84%**	**63%**
GEOTH	**19.60**	**17.42**	**15.14**	**353**	**313**	**272**	6,052	4,715	3,631	**126%**	**98%**	**76%**
TOTAL	**19.46**	**17.15**	**14.74**	**774**	**682**	**586**	13,282	10,266	7,819	**116%**	**90%**	**68%**

5. CONCLUSIONS AND DISCUSSIONS

In summary, the main findings of the paper constitute an estimate for the monetary value of the economic rent (ER) in the above tables with a list of available hydro and geothermal projects. For each project are listed different economic quantities, such as firm energy capacity, market price and value and ER for each project. With different market references, such as a domestic residential market and an EII market, the range of meaningful market references was provided.

Furthermore, the value of the resources, brought to an international market was estimated for each project as well as for the total resources with an assumed transmission cost through a future HVDC cable. Finally it is possible to estimate the ER if the reference market value is the backstop supply, which may be imported fuel for gas turbines etc. although this possibility was not explicitly considered in the case study. It involves estimating the cost of an alternative energy supply if these renewable energy resources were not present. This reference may also be thought of as the most expensive part of the resources, perhaps involving small hydro projects at the most unfavorable project sites. As the resource cost structure involves a series of projects with increasing cost, as we move from favorable projects sites to more unfavorable sites, the reference could be derived from the most costly part of this spectrum or be chosen appropriately among the least favorable projects.

It is well known that the Icelandic electricity market is quite limited in size and the prices in this market would most likely not hold if any or all of the larger project in the market would enter this market. In addition, the future link to a foreign market is far from being near the stage of realization. However, it is well known that such an interconnection is technically feasible and to an increasing extent, it involves a standard technology and solution. Therefore the view set forth in this paper is that the value of such renewable resources should be estimated irrespective of any temporary transmission constraints. This means is that these resources should in this author's opinion be viewed almost as absolute!

There are several arguments for this.

First there is an increased globalization of energy and electric power markets where companies are operating increasingly cross-border.

Secondly, technological advances are rapid in linking and interconnecting such markets technically and financially and these markets cannot be viewed in isolation.

Finally, radically different views on the valuation of these resources seem to have emerged as a part of the deregulation process sweeping these markets worldwide.

These arguments support the notion that there is a specific long-term value of these resources in an international energy/electricity market with an increasing uniformity in price etc. rather than many isolated markets.

The estimate of the ER in this paper has, in the case of Iceland, to our knowledge not been presented previously. However, ER has been estimated in a number of other countries including countries with high abundance of hydroelectric resources [2-9].

There is a growing concern regarding higher future energy prices especially based on fossil fuel. This will undoubtedly make renewable energy resources more valuable. With the advent of global warming and scarce fossil resources, the value of emission-free, sustainable energy is therefore considered likely to increase rather than decrease in the future. However, to realize its value, the renewable energy must be brought to a market for this commodity at a prevailing market price. The resources will then represent an economic benefit to the owner of the resources. This benefit should also expand to the country as a whole and its economy.

The possible price increase of renewable emission-free energy, for instance in the UK market is not explicitly included in this case study, and many would be tempted to forecast a drastic price increase in the coming decades making the ER of many renewable energy resources much more valuable.

The main conclusion of the paper defines the economic rent for the concessions of building projects. The case study calculates this value and estimates it as an annual value and a discounted value.

6. REFERENCES

[1] Ricardo, D., *On the principles of political economy, and taxation*. 1817, London,: J. Murray. viii, 589, [14] p.

[2] Rothman, M.P., Measuring and apportioning rents from hydroelectric power developments. 2000, Washington, D.C.: World Bank. vii, 49 p.

[3] Amundsen, E.S.A., Christian, Rent Taxes On Norwegian Hydropower Generation. Energy Journal, 1992. 13(1)

[4] Amundsen, E.S. and S. Tjotta, Hydroelectric rent and precipitation variability: The case of Norway. Energy Economics, 1993. 15(2): p. 81-91.

[5] Tjotta, E.S.A.a.S., Trade and Price Variation in an Integrated European Power Market. Applied Economics, 1997. 29(6): p. 745 – 757

[6] Amundsen, E.S., Gas power production, surplus concepts and the transformation of hydro electric rent into resource rent. Resource and Energy Economics, 1997. 19(3): p. 241-259.

[7] Banfi, S., M. Filippini, and A. Mueller, Resource Rent Taxation – A New Perspective For The (Swiss) Hydropower Sector, In Politiche Pubbliche, Sviluppo E Crescita, s.i.d.e. pubblica, Editor. 2004, dipartimento di economia pubblica e territoriale – università di Pavia: Pavia. p. 21

[8] Banfi, S., M. Filippini, and A. Mueller, An estimation of the Swiss hydropower rent. Energy Policy, 2005. 33(7): p. 927-937.

[9] Brubaker, E., Water Charges To Hydroelectricity Producers: An International Survey. 1992, Energy Probe: Toronto.

[10] Burness, H.S. and J.P. Quirk, Appropriative Water Rights and the Efficient Allocation of Resources. The American Economic Review, 1979. 69(1): p. 25-37.

[11] Gillen, D.W. and J.-F. Wen, Taxing Hydroelectricity in Ontario. Canadian Public Policy, 2000. 26(1): p. 35-49.

[12] Hreinsson, E. B.: "Environmental, Technical, Economics and Policy Issues of the Master Plan for the Renewable Hydro and Geothermal Energy Resources in Iceland", Proc. UPEC2007 Brighton, United Kingdom, September 4th - 6th, 2007

[13] Hreinsson, E. B.: "Deregulation, Environmental and Planning Policy in the Icelandic Renewable Energy System", Proc. ICCEP/ IEEE, Capri, Italy. May 21st -23rd, 2007

[14] Hreinsson, E. B.: "Supply Adequacy Issues in Renewable Energy and Hydro-Based Power Systems", Proc. of POWERCON 2006, 22nd -26th October, 2006, Chongqing, China

[15] European Energy Commission: "Review of European electricity and gas prices", Issue 8 - September 2006 (http://ec.europa.eu/energy/electricity/publications/doc/review/2006_09_qr08.pdf)

[16] International Energy Agency: "CO2 ALLOWANCE & ELECTRICITY PRICE INTERACTION Impact on Industry's electricity purchasing strategies in Europe", February 2007 (http://www.iea.org/textbase/papers/2007/jr_price_interaction.pdf)

[17] The Evaluation Committee of the Value for Kárahnjúkar Water Rights. Reports (In Icelandic), August 2007. Available at: http://www.lv.is

[18] Hammons, T.J (et. al) "Proposed Iceland/United Kingdom Power Link. An in-Depth Analysis of Issues and Returns", IEEE Transactions on Energy Conversion, Vol. 8, No 3, September 1993

[19] The results of the 1st phase of the master plan (Niðurstöður 1. áfanga Rammaáætlunar), In Icelandic, Reykjavik, November 2003

[20] Auðlindanefnd, álitsgerð. 2000, [Natural resources committee, Report, 2000, in Icelandic] Auðlindanefnd: Reykjavik, 2000
[21] Framtíðarsýn um verndun og nýtingu auðlinda í jörðu og vatnsafls - Skýrsla nefndar iðnaðarráðherra sem skipuð var samkvæmt bráðabirgðaákvæði laga nr. 5/2006, um breytingu á lögum nr. 57/1998. 2006, Auðlindanefnd. (Future prospects about the protection and utilization of sub terrain natural resources and hydroelectric power. The natural resource committee, 2006, in Icelandic)
[22] Auðlindarenta í íslenskum sjávarútvegi og dreifing hennar (Resource rent in Icelandic fisheries and its distribution, The National Economic Institute (NEI). 1999, In Icelandic.
[23] Bernard, J.-T. and R.D. Cairns, On Public Utility Pricing and Forgone Economic Benefits. The Canadian Journal of Economics/Revue canadienne d'Economique, 1987. 20(1): p. 152-163.
[24] Brown, G.M., Renewable Natural Resource Management and Use without Markets. Journal of Economic Literature, 2000. 38(4): p. 875-914.
[25] Gylfason, T., Nature, Power and Growth. Scottish Journal of Political Economy, 2001. 48(5): p. 558-588.
[26] Hartwick, J.M. and N.D. Olewiler, *The economics of natural resource use*. 2nd ed. Addison-Wesley series in economics. 1998, Reading, Mass.: Addison-Wesley. xv, 432 p.
[27] Ambec, S. and Y. Sprumont, Sharing a River. Journal of Economic Theory, 2002. 107(2): p. 453-462.
[28] Hotelling, H., The Economics of Exhaustible Resources. The Journal of Political Economy, 1931. 39(2): p. 137-175.
[29] Salter, W.E.G., Internal and external balance: the role of price and external expenditure effects. Economic Record, 1959. 35(2): p. 226-238
[30] Weber, M.L., Markets for Water Rights under Environmental Constraints. Journal of Environmental Economics and Management, 2001. 42(1): p. 53-64.

BIOGRAPHY

Egill Benedikt Hreinsson (SM'04) received the First Part of Engineering Degree from the University of Iceland, the M. Sc. in Electrical Engineering from the University of Lund, Sweden and the M. Sc. in Industrial and Systems Engineering from Virginia Tech, Blacksburg, VA. In 1972 he joined, Landsvirkjun the National Power Co., Reykjavik working on SCADA/EMS, telecommunication and telemetering systems, power system planning and analysis of hydroelectric system operations and expansion. In 1982 he joined the Department of Electrical and Computer Engineering, Faculty of Engineering, University of Iceland, where he is currently a professor of Electrical Power Engineering. He is the recipient of the Thor Thors fund award. He has been an independent consultant in USA and Europe (including Iceland) in the fields of electric power systems, communications and computer applications in energy systems. He chaired the Iceland Department of Industry Committee for the reevaluation of Electric power safety. His research and teaching interests include power system analysis, economics and operations planning. He is the author/co-author of over 100 scientific and technical articles and papers on electrical power engineering, management and economics.

APPENDIX

Table 5

An experimental data set with Cost and firm energy data for several Iceland projects, from the MP, [19]

Type	Project No.	Project Name	Firm Energy (Gwh/year)	Unit Invest-ment Cost (US$ /MWh/year)	Invest-ment Cost (Million US$	Unit Investment Cost (US$/MWh) w/interest: 5%	6%	7%	Operations Cost (US$/MWh)	Total Unit Cost (US$/MWh) w/interest 5%	6%	7%
Hydro	7	Jökulsá á Fjöllum	4000	264,7	1.059	15,4	17,6	19,9	5,3	20,7	22,9	25,2
Hydro	8	Kárahnjúkavirkjun	4670	287,8	1.344	16,8	19,1	21,6	5,8	22,5	24,9	27,3
Hydro	9	Fljótsdalsvirkjun	1390	271,9	378	15,8	18,1	20,4	5,4	21,3	23,5	25,8
Hydro	14	Skaftárveita	450	118,0	53	6,9	7,8	8,8	2,4	9,2	10,2	11,2
Geotherm.	30	Reykjanes	840	240,3	202	14,0	16,0	18,0	7,2	21,2	23,2	25,2
Hydro	10	Skaftárvirkjun	904	295,0	267	17,2	19,6	22,1	5,9	23,1	25,5	28,0
Geotherm.	43	Hágöngusvæði	840	254,7	214	14,8	16,9	19,1	7,6	22,5	24,6	26,7
Geotherm.	52	Krafla- vestursvæði	840	256,1	215	14,9	17,0	19,2	7,7	22,6	24,7	26,9
Hydro	15	Norðlingaölduveita	650	234,5	152	13,7	15,6	17,6	4,7	18,4	20,3	22,3
Hydro	17	Núpsvirkjun a	1001	326,6	327	19,0	21,7	24,5	6,5	25,6	28,2	31,0
Hydro	18	Núpsvirkjun b	1019	332,4	339	19,4	22,1	24,9	6,6	26,0	28,7	31,6
Geotherm.	x	Various geo-projects	14280	273,4	3.904	15,9	18,2	20,5	8,2	24,1	26,4	28,7
Hydro	19	Urriðafossvirkjun	920	333,8	307	19,5	22,2	25,0	6,7	26,1	28,9	31,7
Hydro	5	Hrafnabjargarvirkjun a	575	305,0	175	17,8	20,3	22,9	6,1	23,9	26,4	29,0
Geotherm.	50	Bjarnarflag	560	263,3	147	15,3	17,5	19,8	7,9	23,2	25,4	27,6
Hydro	1	Skatastaðavirkjun a	1046	352,5	369	20,5	23,4	26,4	7,1	27,6	30,5	33,5
Geotherm.	39	Nesjavellir, stækkun	210	171,2	36	10,0	11,4	12,8	5,1	15,1	16,5	18,0
Hydro	2	Skatastaðavirkjun b	1290	359,7	464	21,0	23,9	27,0	7,2	28,2	31,1	34,2
Hydro	16	Búðarhálsvirkjun	630	333,8	210	19,5	22,2	25,0	6,7	26,1	28,9	31,7
Geotherm.	51	Krafla I stækkun	280	220,1	62	12,8	14,6	16,5	6,6	19,4	21,2	23,1
Hydro	6	Hrafnabjargavirkjun b	618	335,3	207	19,5	22,3	25,1	6,7	26,2	29,0	31,9
Hydro	13	Markarsfljótsvirkjun b	855	351,1	300	20,5	23,3	26,3	7,0	27,5	30,4	33,4
Hydro	11	Hólmsárvirkjun	438	316,5	139	18,4	21,0	23,7	6,3	24,8	27,4	30,1
Hydro	12	Markarsfljótsvirkjun a	735	341,0	251	19,9	22,7	25,6	6,8	26,7	29,5	32,4
Geotherm.	31	Svartsengi,	140	154,0	22	9,0	10,2	11,5	4,6	13,6	14,9	16,2
Hydro	3	Villinganesvirkjun	190	351,1	67	20,5	23,3	26,3	7,0	27,5	30,4	33,4
Hydro	4	Fljótshnjúksvirkjun	405	579,9	235	33,8	38,5	43,5	11,6	45,4	50,1	55,1
Hydro		**Total Hydro**	**21.786**	**GWh/year**	**6.642**	**17,8**	**20,3**	**22,9**				
Geotherm.		**Total Geothermal**	**17.990**	**GWh/year**	**4.801**	**15,6**	**17,7**	**20,0**				
Total		**TOTAL/AVERAGE**	**39.776**	**GWh/year**	**11.444**	**16,8**	**19,1**	**21,6**				

Received 8 February 2008
Paper 08GM1228

7. The European EGS. Project at Soultz-sous-Forets: from Extensive Exploration to Power Production

Nicolas Cuenot, J. P. Faucher, D. Fritsch and A. Genter, European Economic Interest Group (EEIG) Heat Mining, France and D. Szablinski, Pfalzwerke AG, Germany

***Abstract*--** The European EGS project of Soultz-sous-Forêts (France) that was first investigated in 1987 is aimed at producing power by the extraction of the heat stored in deep, fractured crystalline rocks. Extensive research and development contributed to get a better understanding of the geothermal reservoir: large-scale hydrothermal circulation occurs within a network of large permeable faults developed within a Tertiary graben. 3 deep wells have been drilled down to 5 km depth, where a rock temperature of 200°C was reached. At the bottom depth, the horizontal distance between the producing wells is over 1.3 km length, knowing that the injection well is located in the middle. Several hydraulic and chemical stimulations were performed and combined in order to reactivate the system of fractures, which are often sealed by natural hydrothermal deposits. This led to improvement of injectivity and productivity of the wells. After a successful 5-months circulation test done in 2005, we are now building a pilot power plant. Two types of production pumps will be tested for this purpose and a first ORC conversion module of 1.5 MWe will be installed and tested in the beginning of 2008. If the results are promising, a second module should be later installed.

***Index Terms*—**Crystalline rocks, deep wells, Enhanced Geothermal Systems (EGS), geothermal energy, Organic Rankine Cycle (ORC), permeable fractures, stimulation.

1. INTRODUCTION

The European EGS (Enhanced Geothermal Systems) project located in Soultz-sous-Forêts, Alsace, France started in 1987 from the will of the European Commission to develop new sources for power production. The aim of the project is to produce electricity from the heat stored in deep, fractured crystalline rocks. As the geological conditions are very specific, that means that there is no evidence of thermal activity on surface compared to other conventional high enthalpy geothermal sites, the project has needed extensive research and development. The main objectives of the research were a better characterization of the underground geothermal reservoir and a better understanding of the hydrothermal circulation, leading to an optimization of the access to the hot water resource. This corresponds to the first phase of the project, during which 3 deep boreholes were drilled to a depth of 5 km. The second (and current) phase of the project consists in the building of a pilot power plant. A first demonstration module of 1.5 MWe is being installed, as well as all surface facilities. The chosen heat-power conversion scheme is the Organic Rankine Cycle (ORC). This conversion module should be tested in the beginning of 2008 in order to get an estimate of the sustainability of the system, which is mainly linked to the long-term stability of the temperature of the produced water. The produced power should be injected into the French power network.

2. GEOTHERMAL SETTINGS

Soultz-sous-Forêts is located in the northeastern part of France in the northern part of the upper Rhine Graben (Figure 1). This site was chosen because of the observation of a large thermal anomaly in the region and because of a good knowledge of the shallow geology, which was due to former oil exploitation.

2.1 Geological Settings

The site is located within a Tertiary graben. The shallow geology (0 to 1400 m depth) consists in sedimentary layers, overlaying the crystalline basement, which is made of altered and fractured granitic rocks which are older than 330 My [1] and then not related to the present-day thermal anomaly. The geothermal reservoir, into which the boreholes are drilled, is developed within the crystalline rock at a depth between 4 and 5 km.

2.2 Temperature Settings

The temperature profile from the surface down to 5 km depth is presented on figure 2. It was recorded in the 3 deep boreholes with down hole measurements. The geothermal gradient exhibits an irregular shape: around 10°C/100 m in the first 1000 m, then a decrease to 1.5°C/100 m to 2500 m depth and then 3°C/ 100 m to 5 km depth (maximum depth for measurements) [2] [3]. The shape of the gradient is related to the presence of convective cells and fluid circulation within the granite basement [4][5][6].

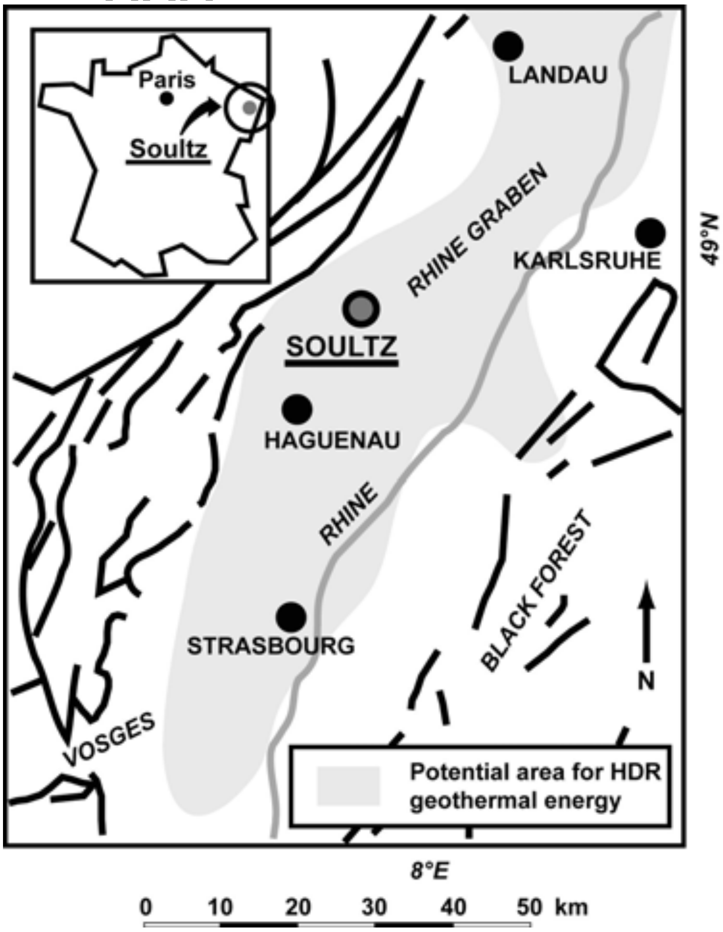


Fig. 1. Location of the geothermal site of Soultz-sous-Forêts. The zone with the highest thermal anomaly is presented in gray color.

2.3 Fracture Network

It has been observed that the underground water circulation is driven by the network of permeable fractures. Extensive research has been made to characterize the properties of the fractures. Geophysical borehole measurements, coring and cuttings analysis showed that fractures, which show a low permeability are almost oriented in a North-South direction and dip sharply [7]. Moreover it appears that hydrothermal deposits, mainly, calcite, silica and clays, which decrease the global permeability of the system, seal most of the fractures.

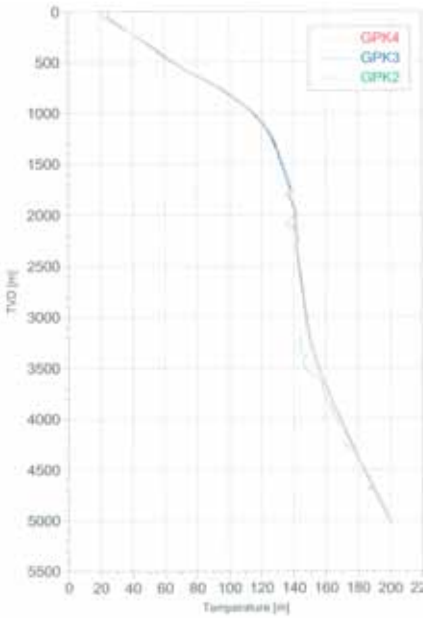


Fig. 2. Temperature profile from the surface to 5 km depth in each well.

The concept of Enhanced Geothermal System comes from this observation. As the overall permeability of the system is not high enough to ensure good hydraulic performances, it is necessary to improve the medium, that is, to reactivate the circulation system by reopening the fractures and establish a connected permeable network. This could be done through either hydraulic or chemical treatments, called “stimulation”, and described below.

3. ACCESS TO THE WATER RESOURCE

5 deep boreholes were drilled at the geothermal site into the granitic basement. One is 3600 m deep, one is 2200 m deep and the three others reach 5000 m depth. All have been at least once stimulated to improve their connection to the fractures network.

3.1 The Deep Boreholes

Figure 3 describes the trajectory of the deep boreholes.

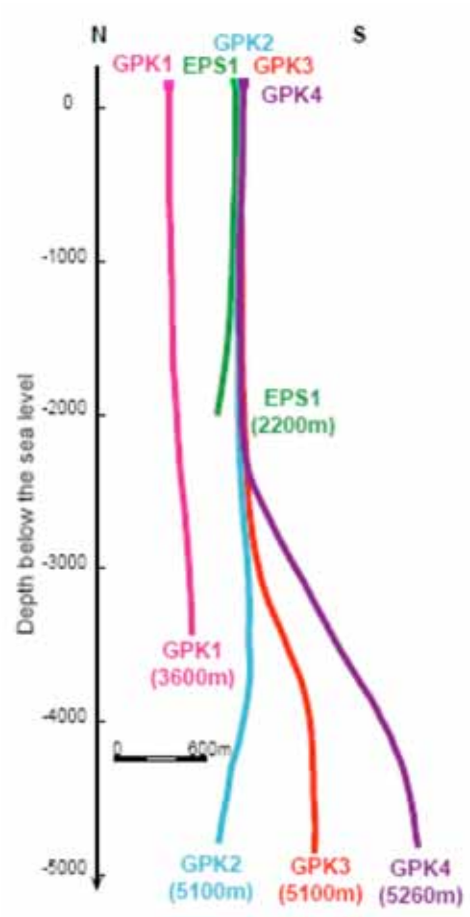


Fig. 3. North-South cross-section of the trajectory of the deep boreholes at Soultz. In brackets is the measured or logging depth [8].

EPS1 (in green) is 2200 m deep (measured depth). This well was cored from 930 m depth to bottom and is currently used as seismic observation borehole. GPK1 (in magenta) is 3600 m deep and was the first drilled well. GPK2 (in blue), GPK3 (in red) and GPK4 (in purple) reach a depth of around 5 km and form the geothermal triplet. GPK2 and GPK4 are set as production boreholes and GPK3 is used to re-inject the cooled water, once its calories have been collected. The wellheads of the GPK-2, -3 and -4 are only 6 m far apart from each other, while there is a distance of roughly 650 m between each bottom hole: this allows the water to circulate on rather long pathways in contact with hot rocks, so that it could be reheated before being pumped again. Such requirements implied that the boreholes' trajectories have to be deviated from the vertical. For instance, the trajectory of GPK4, which is the most deviated, makes an angle of around 30° with vertical.

3.2 Improvement of the Hydraulic Parameters of the System

Two kinds of experiment were tested at Soultz to enhance the hydraulic performance of the geothermal system. The "classical" treatment is the hydraulic stimulation. More recently we also tried to perform chemical stimulations.

1) Hydraulic Stimulations:

Hydraulic stimulations consist in injecting large volume of water (several thousands of cubic meters) at high flow rates (generally, more than 40 l/s), in order to increase the down hole pore pressure, which tends to induce shearing along the fractures planes [9]. This mechanism can help creating permeability within the fracture plane, as the sealing deposits are removed, and also at connecting permeable fractures between them.

After each drilling operation, a hydraulic stimulation was performed in order to:

- improve the connection of the borehole to the network of fractures, that is, increase the permeability of the fractures, which are intersected by the borehole or which are present in the vicinity of the borehole,
- try to improve also the permeability of fractures, which extend far from the borehole.

The direct consequence of hydraulic stimulation is induced microseismicity. On one hand, this could have a negative impact on the population, as some of the earthquakes of larger magnitude (generally higher than 2) can be felt in the surroundings, but on the other hand, induced microseismicity is a mean to monitor the effectiveness of the treatment. The analysis of the extension and the density of the “microseismic clouds” (Figure 4) can give insights about permeability improvement within the geothermal reservoir. Figure 4 summarizes the microseismicity induced during all stimulation tests, which were performed at Soultz, and recorded with a seismic network, installed in observation boreholes [13][14][15]. More than 10000 seismic events can be recorded in each test. The stimulated volume is around 2 km long, 0.5 km wide and 1 km thick. The highest density of microseismic events is observed in the vicinity of the bottom holes, meaning that hydraulic stimulations are mostly effective in that area.

2) Chemical Stimulations:

As the hydraulic performance of the boreholes were not at the required level after all hydraulic stimulations, so that further improvement was necessary, and taking into account that we had to limit the seismic activity, we performed several chemical stimulations. The goal is to try to dissolve the hydrothermal deposits sealing the fractures. Therefore a small proportion of chemicals are added to the injected water. Basic chemical stimulations with diluted HCl were performed in the three wells.

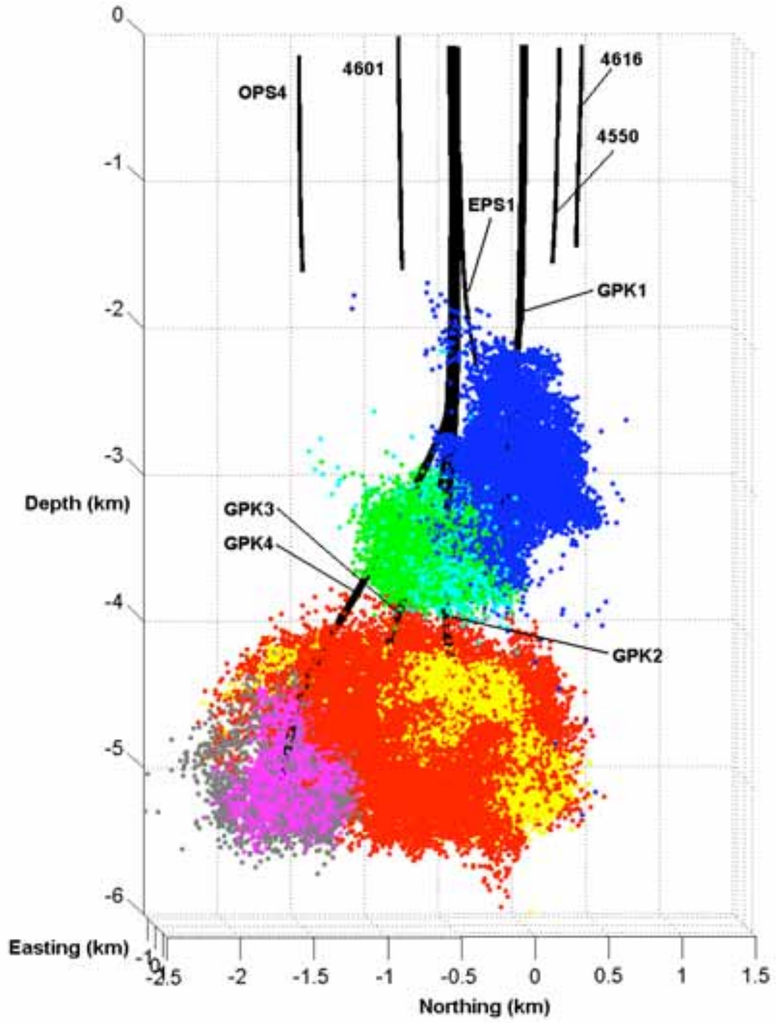


Fig. 4. Microseismic activity induced during stimulation tests. In dark blue, 1993 GPK1 stimulation; in cyan, 1995 GPK2 stimulation; in green, 1996 GPK2 stimulation; in yellow, 2000 GPK2 stimulation; in red, 2003 GPK3 stimulation; in magenta, 2004 GPK4 stimulation; in gray, 2005 GPK4 stimulation. The upper clouds correspond to the development of the former shallow reservoir (3000-3800 m depth) and the lower clouds show the actual reservoir around 5 km depth.

A one-year program was defined in order to select diverse products according to the targets, which are specific known minerals. The program of chemical stimulation was as follows [10]:

- RMA (Regular Mud Acid); the mixture is composed of HCl and HF. The target was minerals like clays, feldspars and micas.
- Chelatants (NTA, nitrilotriacetic acid); the goal was to dissolve calcite.
- OCA (Organic Clay Acid), required for high temperature medium with high clay content. It is composed of citric acid ($C_6H_8O_7$), HF, HBF_4 and NH_4Cl (Schlumberger catalogue). It has a retarding effect, which allows the chemicals to act deeper in the fractures.
- It was specially designed for GPK4, as this borehole exhibits a poor productivity index after hydraulic stimulations and the OCA was also performed in GPK3.

3) Results:

After all hydraulic and chemical stimulation tests, improvements of hydraulic performances of the boreholes have been made.

- GPK2: The initial productivity value, before any stimulation was estimated between 0.01 and 0.03 l/s/bar [16]. After all stimulation tests, the productivity was increased to around 0.8 l/s/bar; this value was estimated during a circulation test and is close to the expected goal of 1 l/s/bar.
- GPK3: An initial productivity value of around 0.3 l/s/bar was calculated [17]. After hydraulic and HCl stimulation, this value remained almost unchanged at 0.35 l/s/bar. It rose up to 0.39 l/s/bar after the OCA stimulation.
- GPK4: After 2 hydraulic stimulation tests, the productivity index increased from an initial value of 0.01 l/s/bar to 0.2 l/s/bar [17]. Figure 5 shows the improvements done through the program of chemical stimulations [11]. The reached and stable value is around 0.5 l/s/bar). The data were recorded during various production tests.

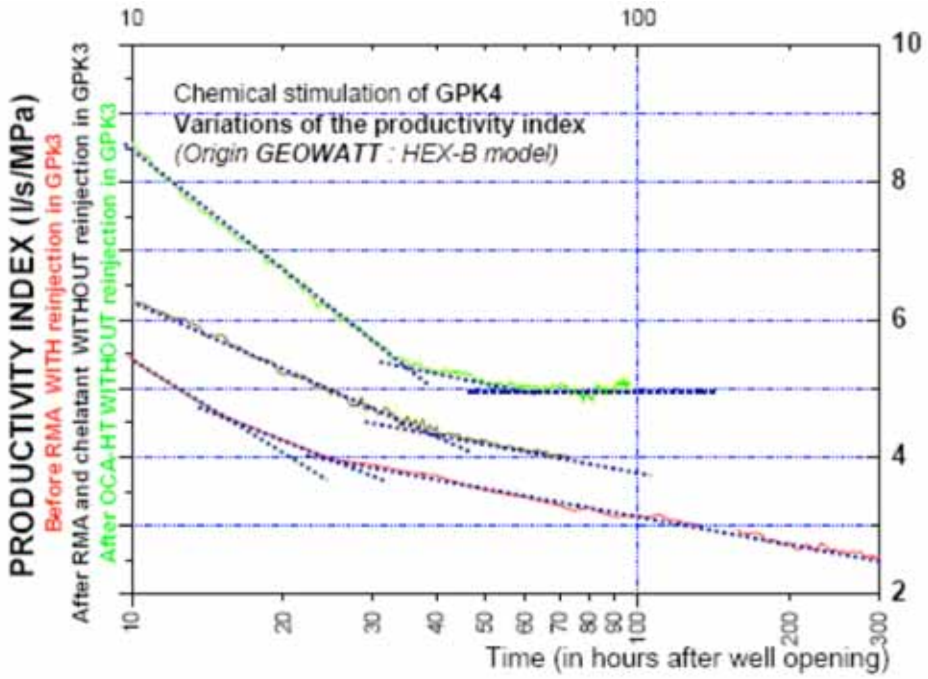


Fig. 5. Evolution of the productivity index after chemical stimulations.

Even though the productivity index of GPK3 and GPK4 do not reach the expected value, it was decided to continue with the building of the power plant and perform the next circulation test with a power output. It is nevertheless expected that productivity and injectivity should increase during circulation, as rock debris and scales, which could plug the access to the rock formation, could be little by little removed by filtering.

4. POWER PRODUCTION

Based on the above exploration and developments, it was decided to test a first conversion module of 1.5 MWe. The different components of the power plant are installed by the end of 2007 and power production should begin in March 2008.

4.1 Basic Principles and Objectives

Figure 6 presents the basic concept of the geothermal pilot plant as it is expected to run. If a production flow rate of 70-100 l/s is reached, corresponding to a thermal power output of roughly 50 MW, the power plant could deliver around 5 MW of electrical power. To reach this goal, it is necessary to install production pumps into the boreholes, because the artesian production flow rates are not sufficient.

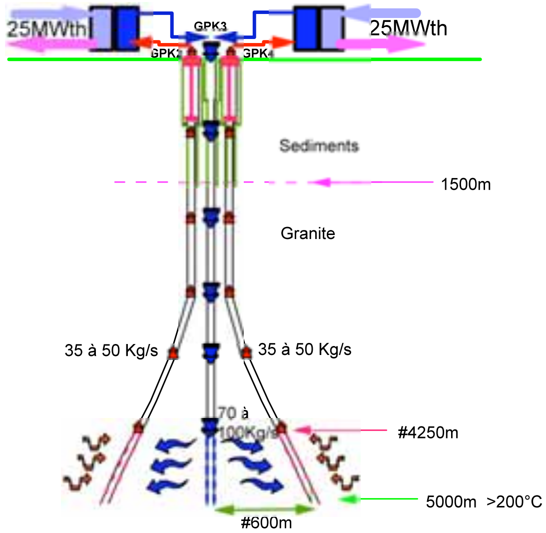


Fig. 6. Principle of the geothermal power plant developed at Soultz.

4.2 Production pumps

2 types of production pumps will be tested, to see if further improvements of the pumping technologies have to be made, regarding the specific conditions of the EGS projects: high temperature and a geothermal fluid, which is corrosive brine containing rocks cuttings. The test will also give insights about the real capacity of the system in term of flow rate, as it is difficult to extrapolate the flow rate obtained under artesian conditions to pumping conditions.

- Line Shaft Pump (LSP, Figure 7): the pump itself is in the well, the motor is at surface and the connection is done through a line shaft. The main advantage is to avoid installing the motor in hot brine, but the possible installation depth is limited and there are mechanical risks with the line shaft, which has to be perfectly aligned. Issues related to corrosion and lubrication of the shaft should also be carefully studied. The pump should be installed at 350 m depth into GPK2, which presents good verticality and is the best producer.

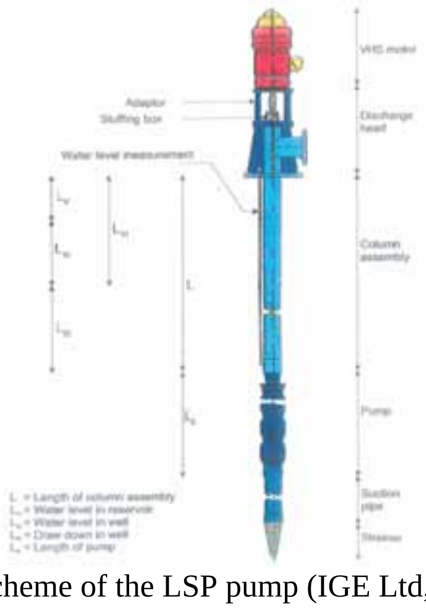


Fig. 7. Scheme of the LSP pump (IGE Ltd, Iceland)

- Electro-Submersible Pump (ESP, Figure 8): both the pump and its motor are installed into the well at any required depth (no depth limitation). The technology is well known for standard conditions, but the problem is to adapt the pump to geothermal conditions: high operating temperature, metallurgy and resistance to corrosion require a specific design. The ESP technology has been adapted from oil industry SAGD (Steam Assisted Gravity Drainage) where the ESP can operate up to 218°C. The pump should be installed at 500 m depth in GPK4, which is the lower productive well.

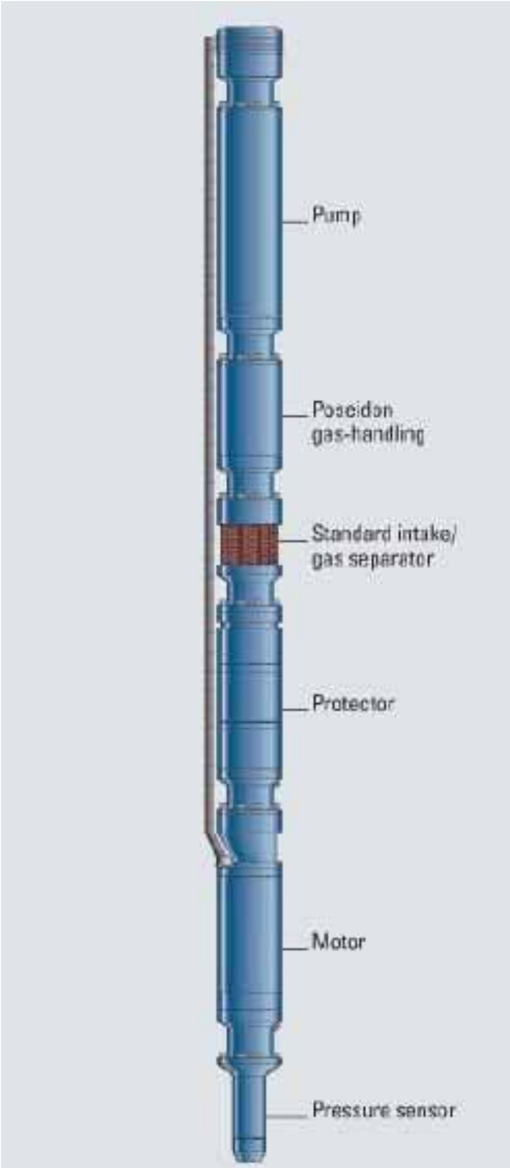


Fig. 8. Scheme of the ESP pump (Reda/Schlumberger)

4.3 Conversion Cycle

Due to the quality of the geothermal brine (high salt content and corrosive compounds), it cannot be vaporized and thus cannot feed directly the turbine. The produced heat shall be transferred to a secondary circuit which involves a low boiling point working fluid. This is the principle of binary cycles. Two kinds of binary cycles were studied for the case of the Soultz-sous-Forêts project: Organic Rankine Cycle (ORC) and Kalina Cycle. Even though Kalina cycle has in theory a higher efficiency, the technology is far more complex than ORC cycles with very few working references around the world. As the purpose of the project is first to demonstrate the feasibility of power production with such a system, the ORC technology has been preferred.

1) The ORC Conversion Scheme:

Figure 9 presents the principle of the ORC conversion technology.

In that frame, the geothermal fluid (expected temperature: 175°C-185°C) enters a first heat exchanger (Vaporizer), transfers the heat to the working fluid, which is transformed into its steam phase to feed the turbine.

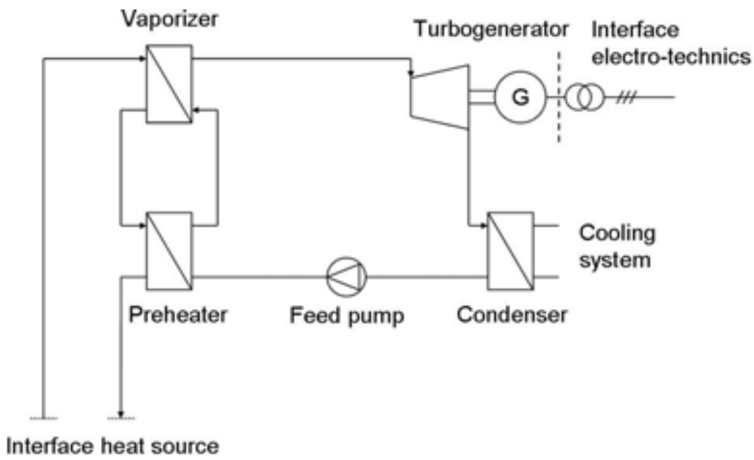


Fig. 9. General scheme of an ORC power plant

Once it expanded in the turbine, the working fluid enters a second heat exchanger (Condenser) to get condensate. A feed pump then pressurizes it before entering a pre-heater, which increases the global efficiency of the system, by the use of the heat, which is still available at the output of the turbine. Figure 10 presents the ORC power plant adapted to the Soultz project, which is supplied by a joint consortium between Cryostar and Turboden. Temperature and pressure are indicated at each step of the cycle.

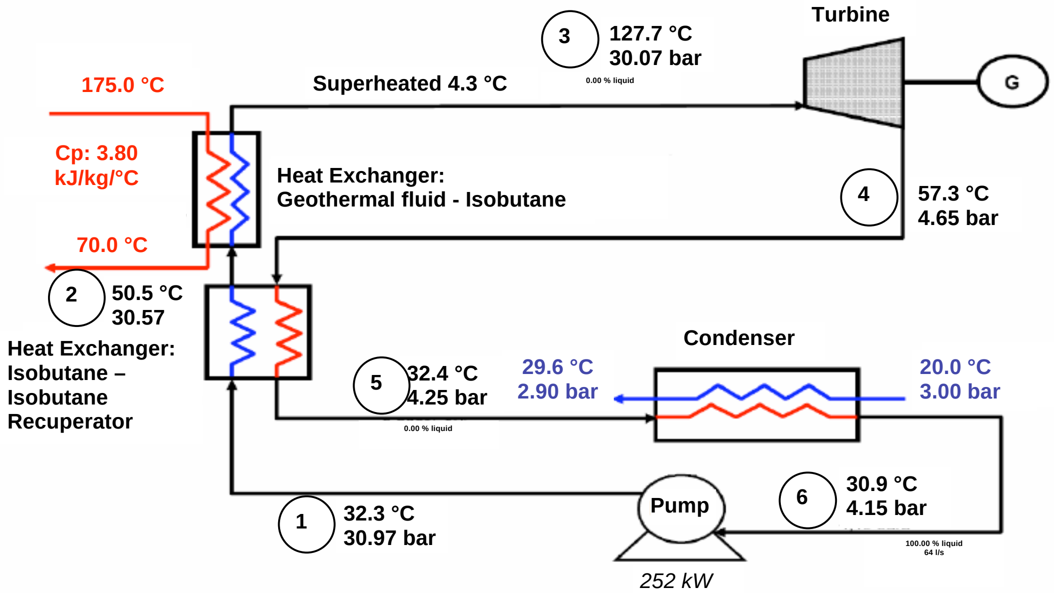


Fig. 10. ORC cycle for the Soultz power plant [12]

2) Working Fluid:

In ORC binary plants, the working fluids are mostly organic fluids. Here isobutane (C_4H_{10}) was proposed by the supplier of the ORC system. This high molar mass fluid (58 g/mol) shows a low temperature of vaporization (-12°C at atmospheric pressure), which allows high running pressures and high flow rates, with a limited volume of fluid and a rather low heating source.

3) Cooling System:

As there is no easily accessible shallow aquifer around the geothermal site, an air-cooling system was required for the power plant, which also limits the impact on environment. It consists in a 9-fans system. Figure 11 shows the air-cooling system being installed.

Fig. 11. Installation of the air-cooling system

4) Turbine and Generator:

The turbine (Figure 12) is radial and should operate at around 13000 rpm.

Fig. 12. The turbine being installed.

The generator (Figure 13) is asynchronous and is running at around 1500 rpm. A gearbox is installed between the two. The generator voltage is 11 kV and the produced power will be increased with a step-up transformer and injected into the 20 kV local network.

4.4 Upcoming Operations

2 kinds of operations are planned for the beginning of 2008. The first is the long-term test of the 1.5 MWe power plant and the second is a production test involving GPK4. The ORC unit is planned to run with the geothermal water produced from GPK2 only, once all the components of the plant will be installed and connected. This will allow getting many data about the long-term behavior of the system.

Fig. 13. Generator (foreground) aligned with the turbine.

The important issues are:

- The sustainability of geothermal water production, and consequently, of power generation,
- The behavior of the production pumps, especially their ability to withstand wearing, corrosion and temperature,
- The seismic response of the reservoir under long-term circulation conditions.

As the borehole GPK4, since the improvement of its hydraulic parameters, has never been fully tested under production conditions, a further test is necessary before connecting the well to the power plant. So a test circulation loop will be installed in parallel to the main circulation loop. It is also useful to have this secondary system in case of maintenance or stop of the power plant: as stopping the down hole production pumps should be avoided, the production can be transferred to this loop. It involves other heat exchangers and a second air-cooling system (Figure 14) to transfer the heat from the geothermal water.

Fig. 14. The second air-cooling system being installed.

The overall scheme of the installation is presented on figure 15.

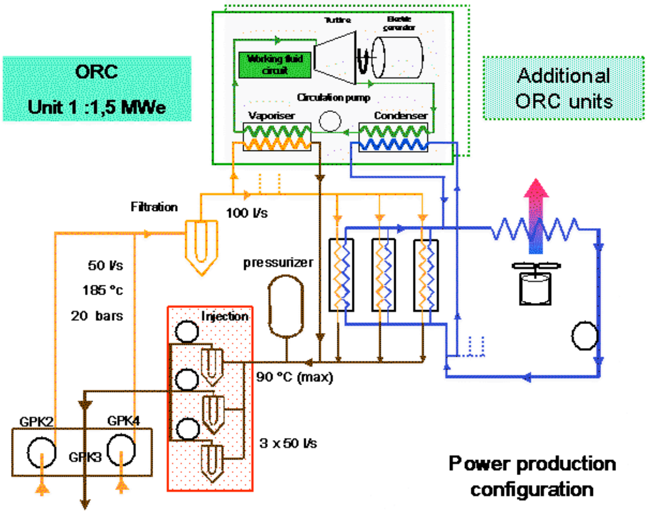


Fig. 15. Scheme of the circulation loops. In yellow: production line; in brown, re-injection line; in green, power production loop; in blue, circulation loop for testing.

The system is built so that the production coming from each well or both can easily be used to feed either the power production loop or the testing loop. If the sustainability of the production is established, then one or two other ORC units could be added to increase the power production of the plant.

5. CONCLUSION

After 20 years of extensive research, the Soultz project is about to deliver its first power production. The success of the demonstration power plant could open the way for a new kind of geothermal power plants using the heat stored in deep, fractured crystalline rocks. The Soultz project has indeed yield to a lot of scientific concepts and technical developments, as well as a better knowledge of the deep, hot, geothermal reservoir. The project has also been a test site for a lot of industrial equipments, which needed to be adapted to the specific temperature and water conditions. The last unknown is the long-term sustainability of power production, which will be tested in 2008. Therefore the methodology to develop and run such a project is now quite clearly established and can be used to develop other future EGS project, involving similar conditions of geology, temperature and water resource. For example a geothermal project has just started with power production in Landau, Germany, whose development took benefits from the experience gained in Soultz-sous-Forêts [18].

6. REFERENCES

[1] Cocherie, C. Guerrot , M. Fanning, and A. Genter (2004), "Datation U-Pb des deux faciès du granite de Soultz (Fossé Rhénan, France)", *C.R. Geoscience* 336, pp. 775-787.

[2] R. Schellschmidt, and R. Schulz (1991), "Hydrothermic studies in the Hot Dry Rock project at Soultz-sous-Forêts", *Geotherm. Sci. Technol.*, 3, pp. 217-238.

[3] D. Pribnow, and R. Schellschmidt (2000), "Thermal tracking of upper crustal fluid flow in the Rhine Graben", *Geophys. Res. Lett.*, 27, pp. 1957-1960.

[4] Clauser, and H. Villinger (1990), "Analysis of conductive and convective heat transfer in a sedimentary basin, demonstrated for the Rhine Graben", *Geophys. J. Int.*, 100, pp. 393-414.

[5] Le Carlier, J.-J. Royer, and E. L. Flores (1994), "Convective heat transfer at the Soultz-sous-Forêts geothermal site: implications for oil potential", *First Break*, 12, pp. 553-560.

[6] Y. Benderitter, and P. Elsass (1995), "Structural control of deep fluid circulation at the Soultz HDR site, France: a review", *Geotherm. Sci. Technol.*, 4, pp. 227-237.

[7] Genter, C. Castaing, C. Dezayes, H. Tenzer, H. Traineau, and T. Villemin (1997), "Comparative analysis of direct (core) and indirect (borehole imaging tools) collection of fracture data in the Hot Dry Rock Soultz reservoir (France)", *J. Geophys. Res.*, 102 (B7), pp. 15419-15431.

[8] Dezayes, P. Chevremont, B. Tourlière, G. Homeier, and A. Genter (2005), "Geological study of the GPK4 HFR borehole and correlation with the GPK3 borehole (Soultz-sous-Forêts, France)", BRGM/RP-53697-FR, 94 pp.

[9] Pearson (1981), "The relationship between microseismicity and high pore pressures during hydraulic stimulation experiments in low permeability granitic rocks", *J. Geophys. Res.*, 86, pp. 7855-7864.

[10] Technical Reports:

[11] S. Portier, L. André, and F.-D Vuataz (2007), "Review of chemical stimulation techniques in oil industry and applications to geothermal systems", Technical Report, Centre for Geothermal Research, Neuchâtel University, Switzerland.

[12] Gérard, and A. Genter (2007), Soultz Enhanced Geothermal System Pilot Plant, 3rd periodic activity report, June 2007, *unpublished*.

[13] Cryostar (2007), "Cycle de Rankine Organique – Soultz-sous-Forêts", Technical Report, Aug. 2007, *unpublished*.

[14] Papers from Conference Proceedings (Published):

[15] R. Baria, J. Garnish, J. Baumgaertner, A. Gérard, and R. Jung (1995), "Recent developments in the European HDR research programme at Soultz-sous-Forêts (France)", in *Proc. World Geothermal Congress*, Florence, Italy, International Geothermal Association, May 19-31, 1995, pp. 2631-2637.

[16] R. Baria, S. Michelet, J. Baumgaertner, B. Dyer, A. Gérard, J. Nicholls, T. Hettkamp, D. Teza, N. Soma, H. Asanuma, J. Garnish and T. Mégel (2004), "Microseismic monitoring of the World's largest potential HDR reservoir", in *Proc. 29th Workshop on Geothermal Reservoir Engineering*, Stanford University, Stanford, California, January 26-28, 2004.

[17] R. Baria, R. Jung, T. Tischner, J. Nicholls, S. Michelet, B. Sanjuan, N. Soma, H. Asanuma, B. Dyer, and J. Garnish (2006), "Creation of an HDR/EGS reservoir at 5000 m depth at the

European HDR project", in *Proc. 31st Workshop on Geothermal Reservoir Engineering*, Stanford University, Stanford, California, January 30-February 1, 2006.

[18] T. Tischner, M. Schindler, R. Jung, and P. Nami (2007), "HDR project in Soultz: hydraulic and seismic observations during stimulations of the 3 deep wells by massive water injections", in *Proc. 32nd Workshop on Geothermal Reservoir Engineering*, Stanford University, Stanford, California, January 22-24, 2007.

[19] P. Nami, M. Schindler, T. Tischner, R. Jung, and D. Teza (2007), "Evaluation of stimulation operations and current status of the deep Soultz wells prior to power production", in *Proc. EHDRA Scientific Conference,* Soultz-sous-Forêts, France, June 28-29, 2007.

[20] J.Baumgärtner , H. Menzel, and P. Hauffe (2007). "The geox GmbH Project in Landau - The first geothermal power project in Palatinate / Upper Rhine Valley", in *Proc. First European Geothermal Review, Geothermal Energy for Electric Power Production*, Mainz, Rhineland Palatinate, Germany, October 29-31, 2007, p. 33.

7. BIOGRAPHY

Nicolas Cuenot received in 2000 a Master's Degree in Engineering Geophysics at the Ecole et Observatoire des Sciences de la Terre (EOST), University Louis Pasteur in Strasbourg (France). His main research interest was seismology and he began a PhD work at the EOST. His studies

dealt with the analysis of the microseismicity induced by hydraulic stimulation at the EGS site of Soultz-sous-Forêts, in order to characterize the physical properties of the geothermal reservoir. Then in 2005 he joined the EEIG "Heat Mining", which manages the Soultz project. He is in charge of the monitoring of the microseismic activity. This involves analysis of the recorded data, but also installation and maintenance of the down hole seismological sensors. His duty was then extended to the general environmental impacts of the project, that is, evaluation and prevention of all possible problems, which could be caused on the surroundings by the development of the project. He is also involved in different kinds of geophysical measurements, which are performed in collaboration with various institutes or companies.