HB 320

ALASKA STATE LEGISLATURE
House Resources Committee

Craig Johnson, Co-Chair

State Capitol Building, Room 126
Juneau, AK 99801-1182
Phone (907) 465-4993
Fax (907) 465-3872
Rep.Craig.Johnson@legis.state.ak.us

Mark Neuman, Co-Chair

State Capitol Building, Room 432
Juneau, AK 99801-1182
Phone (907) 465-2679
Fax (907) 465-4822
Rep.Mark.Neuman@legis.state.ak.us

MEMORANDUM

TO: Representative Mike Chenault, Speaker
Alaska State House of Representatives

FROM: Rep. Craig Johnson and Rep. Mark Neuman
Co - Chairs, House Resources Committee

DATE: March 25, 2010

SUBJECT: Waiver of HB 320 from Committee

The undersigned members of the House Resources Committee request that HB 320, NO ROYALTY ON GEOTHERMAL RESOURCE, be waived from committee. The bill was heard in Senate Resources committee and passed out on March 22th.

Rep. Craig Johnson, Co-Chair

Rep. Mark Neuman, Co-Chair

Rep. Bryce Edgmon

Rep. Kurt Olson

Rep. Paul Seaton

Rep. Peggy Wilson

Rep. David Guttenberg

Rep. Scott Kawasaki

Rep. Chris Tuck

Alaska State House of Representatives

Interim:
716 W 4th Avenue, Suite 630
Anchorage, AK 99501-2133
Phone: (907) 269-0222
Fax: (907) 269-0223

Session:
State Capitol, Room 412
Juneau, AK 99801-1182
Phone: (907) 465-3879
Fax: (907) 465-2069

Sponsor Statement from:

Representative Charisse Millett

R - District 30

RELEASED: February 4, 2010, v26-LS1402\A **CONTACT**: Jeff Turner, 465-3879

HB320 - No Royalty On Geothermal Resource

"An Act removing the royalty obligation for geothermal resources."

Status: PREFILE RELEASED >> (H) RES : 2010-01-29

Electric power generated from geothermal sources is a clean, sustainable and environmentally friendly alternative to fossil fuels. It can play a major part in meeting the future energy needs of the railbelt and other regions of our state.

The problem for any company seeking to build a commercial grade geothermal plant in Alaska is high capital costs that could run 25-50 percent higher than the Lower-48. Operational costs could run 100 percent higher than the rest of the country because the plants will be located in remote locations.

House Bill 320 assists companies in developing geothermal resources discovered in commercial quantities on state land by lifting the 10 to 15 percent royalty payment obligation currently in state statute. In other western states, geothermal power plants rarely have to pay state royalties.

HB 320 is common sense legislation to finally make geothermal power projects economically viable so Alaska can take advantage of the more affordable and very reliable electric power they generate for homes and businesses.

Geothermal electrical generation is a mature and proven technology and has been used for decades all over the world. It creates "green" jobs and unlike other forms of renewable energy it can run 24 hours a day, 365 days a year.

Please join me in supporting HB 320 so our state can move a step closer to a more secure energy future.

###

House Majority Press: http://housemajority.org/spon.php?id=26HB320

Alaska Legislature
Representative Charisse Millett

Session:
State Capitol Building, Room 412
Juneau, AK 99801
Phone (907) 465-3879
Fax (907) 465-2069

Interim:
Anchorage LIO
716 W 4th Ave., Room 630
Anchorage, AK 99501
Phone (907) 269-0222
Fax (907) 269-0223

District 30
Co-chair, House Special Committee on Energy

Date: 2/4/10
Version: 26-LS1402\A

SPONSOR STATEMENT – HB 320

"An Act removing the royalty obligation for geothermal resources."

Electric power generated from geothermal sources is a clean, sustainable and environmentally friendly alternative to fossil fuels. It can play a major part in meeting the future energy needs of the railbelt and other regions of our state.

The problem for any company seeking to build a commercial grade geothermal plant in Alaska is high capital costs that could run 25-50 percent higher than the Lower-48. Operational costs could run 100 percent higher than the rest of the country because the plants will be located in remote locations.

House Bill 320 assists companies in developing geothermal resources discovered in commercial quantities on state land by lifting the 10 to 15 percent royalty payment obligation currently in state statute. In other western states, geothermal power plants rarely have to pay state royalties.

HB 320 is common sense legislation to finally make geothermal power projects economically viable so Alaska can take advantage of the more affordable and very reliable electric power they generate for homes and businesses.

Geothermal electrical generation is a mature and proven technology and has been used for decades all over the world. It creates "green" jobs and unlike other forms of renewable energy it can run 24 hours a day, 365 days a year.

Please join me in supporting HB 320 so our state can move a step closer to a more secure energy future.

LEGAL SERVICES

DIVISION OF LEGAL AND RESEARCH SERVICES
LEGISLATIVE AFFAIRS AGENCY
STATE OF ALASKA

(907) 465-3867 or 465-2450
FAX (907) 465-2029
Mail Stop 3101

State Capitol
Juneau, Alaska 99801-1182
Deliveries to: 129 6th St., Rm. 329

MEMORANDUM February 3, 2010

SUBJECT: Sectional summary for HB 320 (Work Order No. 26-LS1402\A)

TO: Representative Charisse Millett
Attn: Jeff Turner

FROM: Donald M. Bullock Jr.
Legislative Counsel

You have requested a sectional summary of the above-described bill.

As a preliminary matter, note that a sectional summary of a bill should not be considered an authoritative interpretation of the bill and the bill itself is the best statement of its contents. If you would like an interpretation of the bill as it may apply to a particular set of circumstances, please advise.

Section 1. Amends AS 38.05.181(c) to delete a reference to AS 38.05.181(g) that is repealed in sec. 6 of the bill.

Section 2. Amends AS 38.05.181(e) to eliminate royalty share as a factor in a competitive geothermal lease sale.

Section 3. Amends AS 38.05.181(e) by deleting authority for crediting rental payments for a prospecting permit or geothermal lease against royalties.

Section 4. Amends AS 38.05.181(f) to delete a reference to royalties due on a geothermal lease.

Section 5. Amends AS 38.05.182(a) to delete AS 38.05.181 from a spanned reference to provisions relating to royalty obligations.

Section 6. Deletes AS 38.05.181(g) that requires a royalty requirement as a condition of a geothermal lease.

Section 7. Adds a new section to uncodified law stating that secs. 1 - 5 of the Act apply to a lease for a geothermal resource or the renewal of a lease for a geothermal lease entered into on or after the effective date of the Act.

DMB:ljw
10-054.ljw

Witness List for HB 320

1) Paul Thomsen, Ormat
2) Rahm Orenstein, Ormat

Teleconference Sites

Anchorage LIO
Other LIO sites can be added if there is interest

Specialized Information Services Equipment

None required.
Mr. Thomson and Mr. Orenstein will have their own laptops for a PowerPoint presentation.

BRIEFING PAPER

THE CASE IN SUPPORT OF HB 320 FOR REMOVING ROYALTY OBLIGATIONS FOR GEOTHERMAL RESOURCES

EXECUTIVE SUMMARY

Geothermal power offers reliable baseload power that delivers consistent megawatt-hours 24 hours per day, 365 days per year, which is something that most other forms of renewable resources cannot provide. In fact, for a utility or regional transmission organization, a geothermal power plant shows up in a resource plan much like a conventional power plant. Geothermal power is also unique in its lack of emissions, minimal land use, low visual impact and other environmental merits.

Geothermal energy is extremely cost competitive when compared to other forms of renewable energy and fossil-fuel based processes (e.g. natural-gas based plants, as indicated by studies performed by the California Energy Commission[1] [2]).

Multiple western states (e.g. California, Nevada, Hawaii, Utah and Oregon) recognize the merits of geothermal power and have generated geothermal power for decades. These states, among many others, also have multiple new geothermal projects under development.

Although believed to be rich in geothermal resources in various regions around the state, Alaska has yet to develop a single utility-size geothermal power plant. One major hurdle for geothermal development is the relatively high capital cost associated with exploration, drilling and development, as well as high operation and maintenance costs due to the remoteness of resources and the harsh terrain and climate. While capital costs for development and construction of geothermal power plants in other states is typically around $4,000/kW[3], in Alaska estimates typically increase 25%-50%. Operation and maintenance costs of geothermal plants in Alaska are expected to be as much as 100% higher than the respective lower 48 states, again due to the typical remoteness of the plants.

In other western states, geothermal power projects rarely are required to pay State royalties. A report by the Geothermal Energy Association explains geothermal royalties vary depending on land ownership type (Federal, state, private) yet tend to range from 0.5% to 5.5% of revenues[4]. The majority of the geothermal projects currently under

---

[1] http://www.energy.ca.gov/2009publications/CEC-200-2009-017/CEC-200-2009-017-SD.PDF

[2] http://www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SD.PDF

[3] Climate Change Business Journal, April/May 2009

[4] http://www.geo-energy.org/publications/reports/Socioeconomics%20Guide.pdf

development in the US are on Federal lands, where BLM regulations call for revenue royalties of 1.75% during the first 10 years and 3.5% thereafter.

In Alaska, despite the fact that geothermal development faces greater financial challenges compared to other states, the current statutes call for royalty rates of 10%-15%, similar to oil, gas and mineral regulations. Ormat believes this rate is cost-prohibitive and is one of the reasons no utility-size geothermal plant has ever been built in the state.

Financial analysis shows that removing the 10-15% royalty obligation will lower the operations and maintenance cost by 10-15%, therefore lowering the kWh cost by 10-15%. Removing royalty obligations from geothermal power plants in Alaska will serve to acknowledge the unusually high costs of geothermal development, operation and maintenance while incentivizing geothermal development in the state. This will ultimately lower the cost of clean, reliable power to the ratepayers.

Strategic Information for the Climate Change Industry

CLIMATE CHANGE BUSINESS JOURNAL®

Volume II, No. 4/5 April/May 2009

Global Geothermal Industry Balances Short-Term Development With Long-Term Investment in EGS

If the Low-Carbon & Renewable Power segment of the Climate Change Industry were a baseball team, geothermal energy would be the underrated veteran shortstop who doesn't hit many homers but fields consistently, rarely strikes out and scores runs on a regular basis. Let the stars like wind turbines and solar photovoltaic (PV) panels get the headlines; let the sports writers pump up the egos of rookies like thin-film PV, cellulosic biofuels and solar thermal power. Geothermal will be there to rack up solid stats and deliver for the team and the fans year after year.

Geothermal power's workmanlike quality stems from the fact that it offers something that wind and solar cannot provide: reliable baseload power that can be counted on to deliver megawatt-hours 24 hours a day, 365 days a year. In fact, for a utility or regional transmission organization, a geothermal power plant shows up on a resource plan grid like a conventional power plant.

In a broad context there are really three ways to look at geothermal energy:

1) Traditional steam-generated electricity generation, or hydrothermal, as it is often known, is site-dependent and has rather limited potential of perhaps 30,000 MW in the United States;

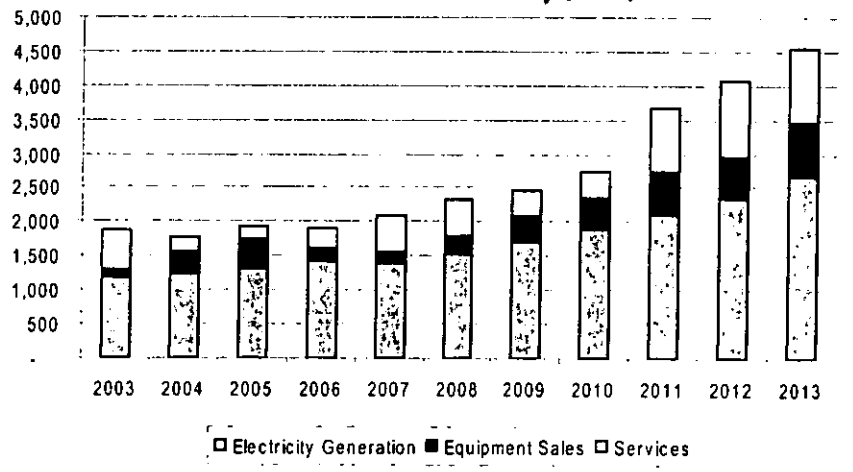
The Geothermal Energy Industry

Geothermal energy was a $6.8 billion global industry in 2008, generating 66,000 GWh of electricity worth close to $4.8 billion, $1.1 billion in equipment sales and $900 million in service revenues. The United States market is the world's largest at $2.3 billion, and forecasts are for high growth as a strong pipeline of projects are developed in the next few years when carbon regulations are expected to drive a subsequent wave of growth.

2) Enhanced geothermal systems (EGS) allow electricity generation from hot dry rock, thus opening up the map and the potential for geothermal power. But it is still early stages for EGS; and

3) Direct use geothermal encompasses space heating, hot water, process heat, pools, greenhouses and aquaculture. Direct use is exploited in more countries than electricity generation (see box on page 5), but CCBJ classifies it as an energy efficiency application in that it replaces conventional sources of energy. The main growth in direct use during the last decade has been geothermal or ground-source heat pumps for space heating.

The U.S. Geothermal Industry ($mil)



Source: Climate Change Business Journal from a market model dervied from a variety of sources including Geothermal Energy Assn., International Geothermal Assn., Emerging Energy Research, New Energy Finance and company, government and academic sources. Services include exploration & resource assessment, well field drilling & development, plant design & construction.

CLIMATE CHANGE BUSINESS JOURNAL®

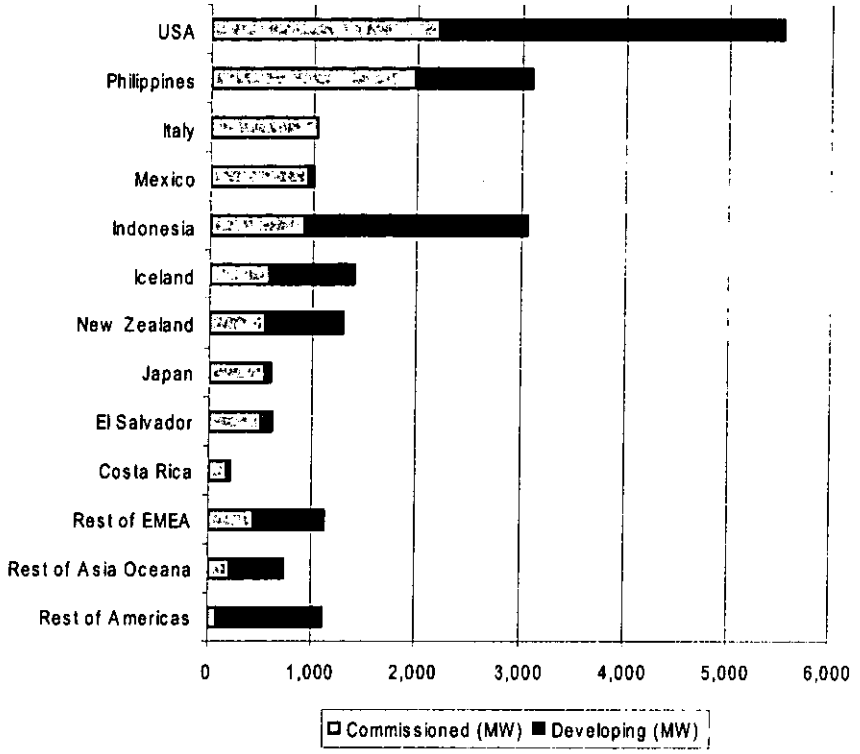
Vol. 2, No. 4/5 ISSN 1940-8781
April/May 2009

Climate Change Business Journal® newsletter is published 8 times a year (includes 4 double issues) by Environmental Business International Inc., 4452 Park Blvd., Suite 306, San Diego, CA 92116. Phone: 619-295-7685 or email info@climatechangebusiness.com

How to subscribe

Annual subscriptions are US$995 in the U.S. and Canada, $1,045 overseas; corporate electronic subscriptions start at $2,500 (up to 5 users). To order or for more information call (619) 295-7685 x 15, email info@climatechangebusiness.com, or go to www.climatechangebusiness.com, where you can also sign up for the complimentary CCBJ Weekly News.

Global Geothermal Capacity and Development Pipeline (MW)



Source: New Energy Finance, Mark Taylor presentation, April 2009. Commissioned total is 10,162 MW in 2009 with 10,663 MW in development. EMEA is Europe, Middle East and Africa

Hence the focus of this review on electricity generation and its tie in with the power sector. Geothermal electricity "bridges both the conventional feedstock and renewable energy options for electric power generation rather uniquely," wrote **Deloitte** in a February 2008 report for the **U.S. Department of Energy (DOE)**. Geothermal's baseload characteristics allow "it to compete with other baseload feedstocks such as coal, natural gas and nuclear. At the same time, geothermal energy is a clean, renewable resource that competes with other renewable energy options such as wind and solar [making] it an attractive option for reliable and scalable generation while satisfying renewable energy voluntary or mandatory portfolio standards."

Yet, geothermal both in the United States and the rest of the world is not being deployed at a particularly brisk pace. At the end of 2008, cumulative worldwide installed capacity was between 9,900 and 10,500 MW, including 2,200 MW in operating capacity in the United States, according to estimates from **New Energy Finance** (NEF) and **Emerging Energy Research**. (Some 400-500 MW of capacity at the 1,400-MW Geysers project in California is on standby.)

Globally the pipeline of hydrothermal electricity projects currently in development exceeds the installed capacity by about 500 MW (see chart on page 2). The United States, Indonesia, the Philippines, Iceland and New Zealand account for 77% of the 10.7-MW pipeline, according to NEF estimates as of April 2009.

How Geothermal Stacks Up Against Other Renewables

Not only is geothermal's 10,000 MW in current global capacity easily less than 10% of the comparable capacity figure for wind power (121 GW worldwide) and less than two thirds of solar PV's installed capacity (15 GW), but geothermal electricity generation represents a comparatively anemic growth rate. At the end of 2003, global geothermal capacity was at 8,400 MW, meaning average annual growth from 2003-2008 was about 3.4%. Not bad if you're in the soup business, but in the clean energy business that kind of growth doesn't generate much excitement. By contrast, PV's 5.95-GW jump in 2008 as tallied by **SolarBuzz** represented one year growth of 110%. Wind power's leap forward in 2008 as tallied by the **Global Wind Energy Council** was 29%.

Even with the recent growth in wind and solar, renewable sources remain fairly insignificant in the 19 million GWh global electricity picture. In terms of electricity production, however, geothermal's superior capacity factor makes its contribution to global electricity generation more substantial than solar and close to half that of wind—at least in 2006, the most recent year for which the International Energy Agency publishes data. According to the IEA, geothermal electricity accounted for 59,200 GWh or 0.31% of global electricity generated, with wind at 0.7% and solar 0.2% in the same year. Coal (41%), gas (20%), hydro (16%), nuclear (15%) and oil (6%) made up 98% in 2006, according to IEA. Of course, lumping geothermal with the other renewables does de-emphasize its higher capacity factor (see table at right) and predictable baseload contribution valued by utilities.

As a business segment, CCBJ estimates the U.S. geothermal industry accounted for $2.3 billion in revenues in 2008, or 34% of the $6.8 billion global total. The $7 billion figure for the global geothermal industry compares to $56 billion for wind and $28 billion for solar (See dedicated CCBJ editions from 2008).

CCBJ defines the geothermal industry in three subsegments: electricity generation; equipment sales; and services. The latter includes exploration & resource assessment, well field drilling & development and plant design & construction. Electricity represents about 70% of the global total, but the ramping up of growth until the 2008 financial meltdown had corresponding investments in site evaluation, drilling, etc. that tilted the share of revenues more to services in growing mar-

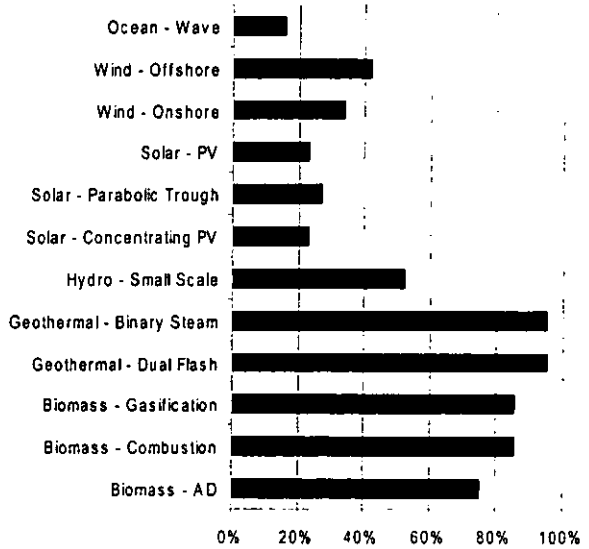
Typical Market Drivers for Renewable Energy

Driver	Developed markets	Emerging markets
Power prices	+	++
Demand growth	++	+++
Reliance on energy imports	+++	++++
Environment	++++	+

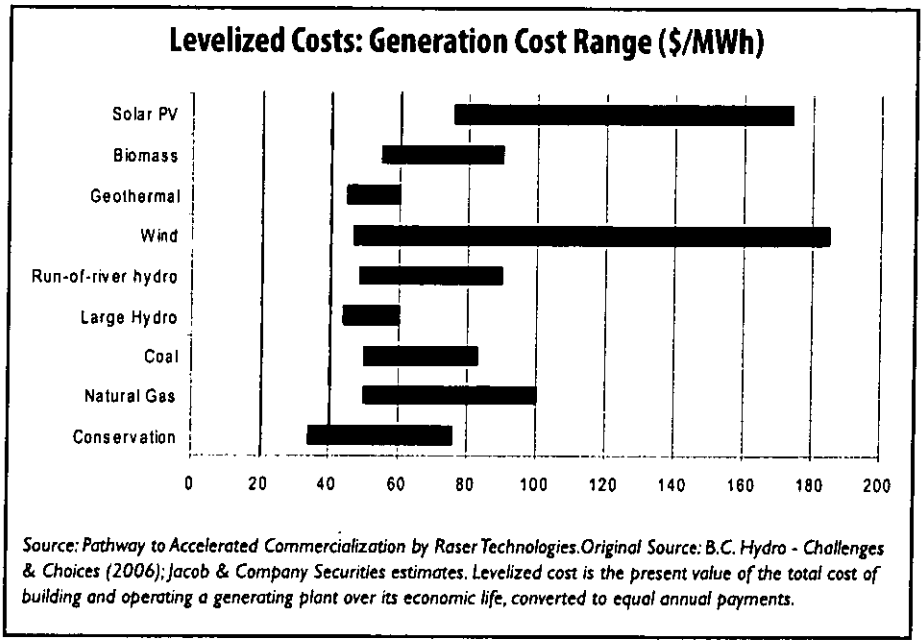
Note: Each + indicates relative importance of market driver; Drivers are the same worldwide, but priorities vary.

Source: Ormat Technologies, Inc., presentation by Rahm Orenstein at Greenpower Conferences' March 2009 Geothermal Innovation and Investment conference

Capacity Factors for Selected Renewables (Average Net Capacity %)



Source: Presentation by Raser Technologies
Original Source: Glitner Geothermal Report, September 2007



Source: Pathway to Accelerated Commercialization by Raser Technologies. Original Source: B.C. Hydro - Challenges & Choices (2006); Jacob & Company Securities estimates. Levelized cost is the present value of the total cost of building and operating a generating plant over its economic life, converted to equal annual payments.

kets, the U.S. included. CCBJ forecasts indicate that following a delay resulting from the freezing of credit and financing, the geothermal market will resume a growth trajectory and reach $5 billion in the U.S. and $16 billion globally by 2014.

Revenues available to specialist consulting & engineering firms could arguably be the total service amounts of roughly $1 billion globally the past few years, with a jump to $2-3 billion provided nothing further curtails the current pipeline or forecasted growth trajectory. A significant portion of these revenues, however, would be drilling or construction, meaning pure C&E project revenue would likely be closer to half these figures.

According to a variety of analysts and CCBJ interviews with industry leaders and experts, the growth of geothermal has historically been hampered by several constraints and challenges. In the first place, without a technological revolution like that promised by enhanced geothermal systems (EGS, also known as hot dry rock technology; see EGS/HDR feature on pages 29-31), geothermal power can only be developed in countries with suitable underground geothermal resources. Most geothermal resources are located along the seismically active Ring of Fire that roughly follows the coasts of the Pacific Ocean. Other resource areas include Eastern China and the Himalayan Belt, the Caribbean, Iceland, The Azores, Canary Islands, Italy, parts of Northern and Eastern Europe, the Eastern and Southern Mediterranean and Kenya, Tanzania and other countries is the East Africa Rift zone.

Investors prefer to buy geothermal companies or their operating power plants rather than invest in new projects.

In the second place, geothermal development is to a certain degree a speculative enterprise. Like wildcatters in the oil industry, geothermal developers must spend millions of dollars drilling for underground resources that they're not sure are present—or present in the quantities that will lead to their expected return on investment. "Geothermal projects have distinctly different challenges than other, more traditional, renewable technologies such as wind, solar, and biomass," notes the DOE's office of Energy Efficiency and Renewable Energy (EERE) in its *Geothermal Tomorrow* report. "Geothermal projects require subsurface exploration and well field development and have greater upfront risk because the geothermal resource is not confirmed without drilling."

Geothermal developers at Greenpower Conferences' March 2009 Geothermal Innovation and Investment conference in San Francisco said that typically 20% to 30% of the wells they drill—wells costing from $1.5 million to $10 million—end up hitting "dryholes." While not always physically dry, these dryholes are of sub-commercial enthalpy (heat energy). Compounding this dryhole risk is the fact that in the United States and some other regions, many of the best and most easily accessible geothermal resources—those with surface expressions like hot springs and fumaroles—have already been developed. To tap undeveloped resources for new power plants, developers must take on more risk in their drilling and development efforts.

As described in the developers roundtable article that follows this overview on page 9, as recently as the summer of 2008 developers could obtain debt financing to finance some of this resource and wellfield development work. Today the pendulum has swung the other way. Those lenders willing to finance geothermal projects require that developers sink wells and have proven resources—"steam behind the pipe" as they call it—before they will finance power plant construction. Separately with the depressed market caps of publicly held geothermal developers, private equity funders would rather buy companies or their assets than invest in new projects. Financial institutions in the market for tax credits are few and far between. And except for companies with a technology play in the emerging EGS segment, venture capitalists aren't interested in geothermal companies because of the lack of upside potential.

In this difficult environment, geothermal developers are urging the U.S.

Geothermal Energy: Opportunity and Challenge

Advantages from Utility Perspective

- Firm 24x7, not an intermittent resource
- Competitive cost
- Small physical footprint with minimal environmental impact
- 20-40 MW size does not require EHV transmission
- Credibility from years of success
- Recognized as a well-established industry

Some Development Challenges

- Financing uncertainty & heightened risk aversion
- Resource uncertainty
- Consolidating site control
- Prospecting/drilling cost on front-end
- Permitting
- Long lead-time
- Supply curve: progression to lower quality prospects

Challenges for Utilities

- Increasing RPS requirements puts pressure on utilities to turn to big projects
- Greenfield project failure an issue
- Uncertainties regarding amount, timing, and cost at odds with competitive resource procurement
- Operating plant/resource performance predictability an issue
- Few players in geothermal industry have the financial strength to go the distance

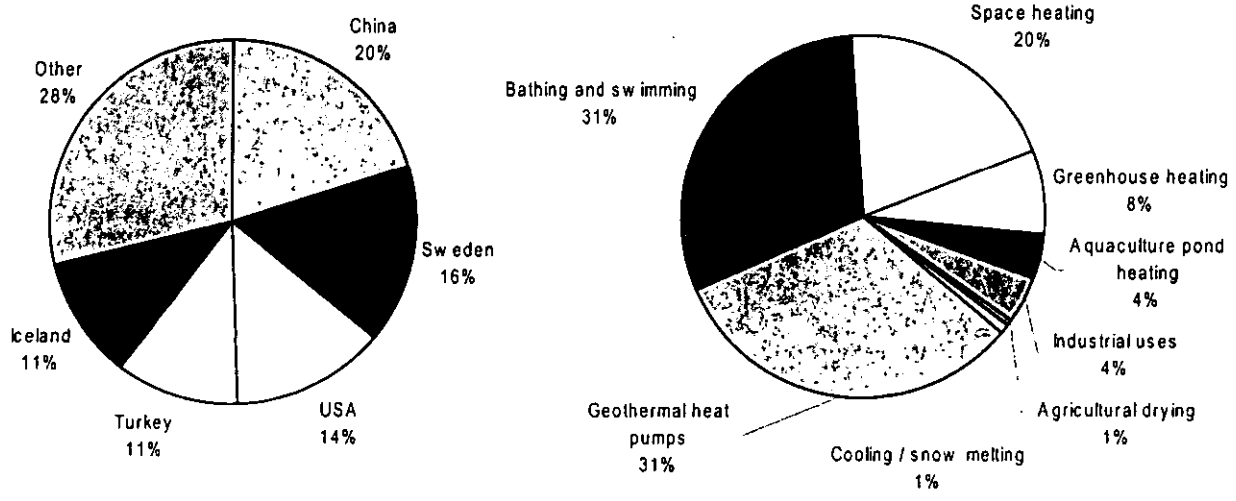
Source: NV Energy, March 2009 presentation by Thomas R. Fair, Vice President Renewable Energy

Direct Use Geothermal and Impacts on Climate Change

Electricity is produced from geothermal sources in 24 countries. Direct application of geothermal energy has been reported by 72 countries. In 2005, the worldwide use of geothermal energy was 57 TWh/yr of electricity and direct use was 76 TWh/yr, as reported by the **Intergovernmental Panel on Climate Change** (IPCC), a scientific intergovernmental body set up by the World Meteorological Organization and by the United Nations Environment Programme. Six developing countries are in the top 15 countries in direct use, with China at the top of the list. Direct use utilizes low-enthalphy geothermal fields that don't produce hot water at temperatures sufficient to generate power. While many firms engaged in geothermal electricity also work on direct-use projects, the segment is more driven by utilities, governments or companies using the heat directly. (Note: IPCC has released forecasts for geothermal electricity with global capacity reaching 24 GW in 2020, 46 GW in 2030, 90 GW in 2040 and 140 GW in 2050)

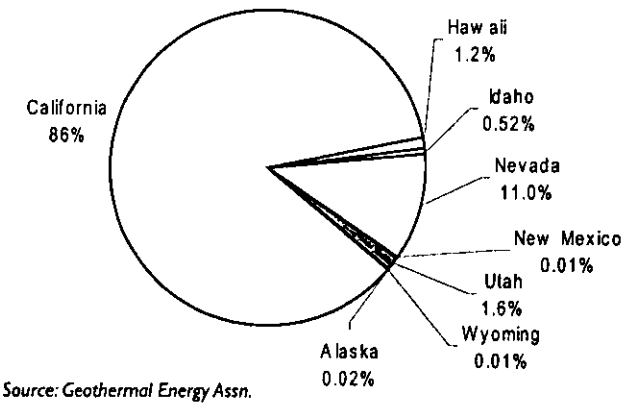
Direct Use Applications: Direct applications of geothermal energy are for space heating 52%, hot water (bathing and swimming) 30%, horticulture (greenhouses and soil heating) 8%, industry 4%, and aquaculture (mainly fish farming) 4%, according to John Lund in his paper *World-Wide Direct Uses of Geothermal Energy 2005*. Ground-source heat pumps are growing due to their ability to utilise groundwater or ground-coupled temperatures. According to IPCC, scenarios for future development show only a moderate increase in traditional direct use applications, but an exponential increase in heat pumps, as geothermal heat pumps can be used for heating and/or cooling in most parts of the world. In addition, geothermal heat pumps driven by fossil-fuel electricity reduce CO2 emissions by at least 50% compared with fossil-fuel fired boilers. If the electricity that drives the geothermal heat pump is produced from a renewable energy source like hydropower or geothermal energy the CO2 emission savings are up to 100%. The total CO2 emission reduction potential of geothermal heat pumps has been estimated to be 1.2 billion tonnes per year or about 6% of global CO2 emissions. Geothermal heat pumps will be covered in CCBJ's upcoming edition on energy efficiency and demand response.

Geographic and Application Breakdown of Direct Use Geothermal



Source: Lund, Freeston, and Boyd, World-Wide Direct Uses of Geothermal Energy 2005, published in Proceedings of the World Geothermal Congress 2005

2009 U.S. Geothermal Power Capacity On-Line



Source: Geothermal Energy Assn.

Department of Energy to use some of its ARRA funding—$400 million for geothermal and $6 billion for innovative technology loan guarantees—to subsidize drilling. As of May 2009, DOE had not issued guidance on this question. In international developments, the recession's impact on Icelandic geothermal firms has been amplified by the collapse of Iceland's currency. With the krona almost worthless on the international market, Icelandic geothermal developers that had set their sights on developing projects in foreign markets have scaled back to focus on the significant potential in their homeland.

Western States' Near-Term New Geothermal Power Capacity

	Capacity MW	Number of Sites
Alaska	20	3
Arizona	20	2
Colorado	20	9
California	2,400	25
Hawaii	70	3
Idaho	860	6
Nevada	1,500	63
New Mexico	80	6
Oregon	380	11
Utah	230	5
Washington	50	5
Total	**5,630**	**138**

Source: Western Governors' Association, Geothermal Task Force of the Clean and Diversified Energy Initiative. The task force concluded that Western States have a capacity of 13,000 MW that can be developed on specific sites within a reasonable timeframe, of these, 5,600 MW are considered viable for commercial development by 2015.

Long-Term Market Drivers Look Solid

The phrase "when the economy recovers" is becoming a cliché of analysts and commentators looking at virtually all industries, but there's really no other way to say: When the economy recovers, and when the prices of oil and gas resume their inevitable rise into the $100-plus territory, the geothermal power industry's prospects will improve. The CCBJ global market forecast, not that dissimilar from the base-case capacity-growth scenario of Emerging Energy Research (EER), has 2011-2014 annual growth in the high teens, with double-digit growth persisting to 2020.

Market drivers for geothermal power are fundamentally sound: In the developed world, renewable energy standards and greenhouse gas caps are pushing utilities toward low-carbon generation, and geothermal's baseload qualities give it advantages over solar and wind. As outlined in the chart on page 3, energy supply and security are also drivers, as is power price in regions such as the Caribbean and parts of South Asia that are highly dependent on imported diesel oil for power supply. Some developing country markets are using feed-in tariffs popularized mostly for other renewables in Germany and other developed nations.

With renewed growth, however, the geothermal power segment will have to contend with a couple of looming challenges. One is lack of access to drilling rigs. When oil prices were in the stratosphere and demand was outstripping supply, geothermal developers had a difficult time contracting for rigs and crews. With the drop in prices and demand, that has gotten easier; but rising prices and demand will inevitably cause drilling demand to rise. Another challenge will be recruiting and training staff. "The professional staff available in geothermal is minute," said Doug Glaspey, CEO of U.S. Geothermal, at the March conference. "In order to grow, you have to have skilled professionals, and that's a very difficult thing to accomplish in this business today." Investment capital is also required, and although the flow of venture money into cleantech businesses was tallied at over $8 billion in 2008, geothermal is not the sexiest category.

EER states that geothermal power plant investment could reach $13-20 billion by 2020, representing cumulative investment in geothermal exploration, drilling, and power plant construction. In comparison with EER's broader power generation forecasts, geothermal is the fourth-largest market for cumulative renewable power generation investment between 2009 and 2020, behind onshore wind, solar PV, and biomass, but ahead of offshore wind, CSP, and small hydro globally by 2020.

EER's base-case growth scenario forecasts 20 GW of geothermal installed during the 2010s, with their high-growth scenario at about 1.5 times that or about 30 GW. The vast majority of growth in both scenarios is North America and Southeast Asia, although the rest of the world accounts for as much as 25-30% of growth in some years of EER's forecast. A few new markets are expected to see sustained growth, led by Chile, Turkey, Russia, East Africa, and Central America. Established markets in Iceland, Mexico, and New Zealand are also expected to

Regions Where Geothermal Companies Expect to Increase Their Work in 2009-2011

United States	69%
Europe	31%
Indonesia	31%
Central America	23%
Australia	15%
Africa	12%
China	12%
New Zealand	12%
Philippines	12%
Rest of Asia	12%
Canada	12%
Italy	8%
Japan	8%
Mexico	8%
India	8%
Chile	8%
Iceland	4%

Source: CCBJ 2009 Geothermal Survey conducted in April 2009. Question was:What countries or regions are you expecting to increase your work in over the next three years? n=26

continue to tap their potential. Australia is what EER calls the largest region of uncertainty, as its substantial goal of bringing online over 2 GW of geothermal by 2020 remains contingent on successful deployment of unproven EGS.

As mentioned, the United States leads the world in online capacity of geothermal energy and continues to be one of the principal countries to increase its geothermal growth. Geothermal electric power generation is centered in eight U.S. states: Alaska, California, Hawaii, Idaho, Nevada, New Mexico, Utah and Wyoming with Oregon and Colorado coming on line. Total U.S. installed capacity was 3,040 MW as of March 2009, according to GEA's *U.S. Geothermal Power Production and Development Update* that includes some units on standby. With a pipeline of now more than 4.4 GW of confirmed projects, the U.S. geothermal market is poised to more than double existing capacity over the next five years, says EER, with U.S. carbon legislation and national

Geothermal Industry Gameboard Not Too Crowded

The geothermal power industry consists of project developers that identify, finance and build geothermal power plants; consulting engineering and technical firms that identify and quantify geothermal resources, conduct environmental analyses, design, operate and maintain projects; drilling firms that drill wells for exploration and production; engineering, procurement and construction (EPC) firms that build geothermal power plants; manufacturers of turbine generator sets, heat exchangers and other equipment; and other specialty firms. Some firms perform multiple roles, for example, manufacturers sometimes develop their own projects and EPC firms often provide multiple technical services with in-house staff. Exploring for and developing geothermal power resources requires specialized expertise that is concentrated in a few countries including Japan, Iceland, the United States, Canada, New Zealand, Australia and the Philippines.

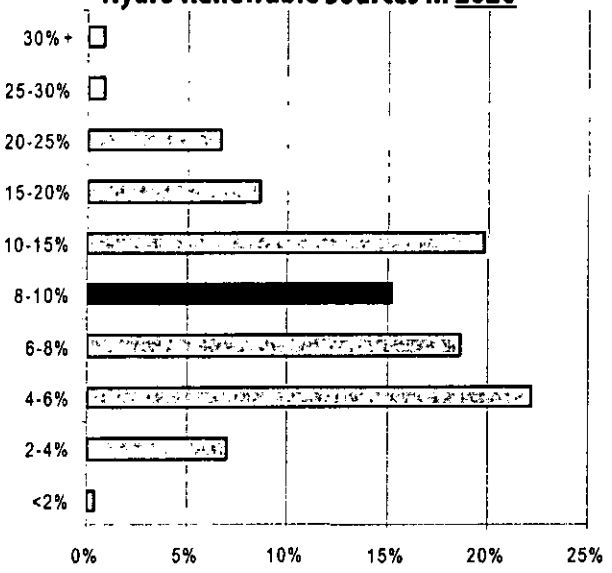
The number of firms in the industry is very small compared to other energy sectors. There are 11 manufacturers of geothermal turbine generator sets and related power plant components. They include: Alstom (France), Ansaldo (Italy), Fuji Electric (Japan), GE Energy (United States), Mitsubishi Heavy Industries (Japan), OAO Kalugo Energo (Russia), Ormat Technologies (United States), Siemens (Germany), Turboden (Italy), Toshiba (Japan) and UTC/Pratt & Whitney (United States). At the most recent international trade show of the **Geothermal Energy Association** in the United States, there were fewer than 100 exhibitors.

Geothermal project developers and power plant owners can be divided into two categories: 1) major independent power producers (IPPs) and utilities and 2) pure-play geothermal developers. The former category includes (U.S. companies unless stated): ArcLight Capital Partners/Terra-Gen Power, Calpine, Chevron, ENEL (Italy), EnBW (Germany), Geysir Green Energy (Iceland), LaGeo (El Salvador), Mid-American/CalEnergy, Ormat Technologies and PNOC EDC (The Philippines). Unocal and Chevron had historically been active developers of geothermal power in Southeast Asia. In 2005, Chevron acquired Unocal, and Chevron today is the world's largest private owner of geothermal power plants with combined capacity of 1,273 MW in the Philippines and Indonesia. Pure-play developers include: Magma Energy (Canada), Nevada Geothermal Power (Canada), Polaris Geothermal (Canada), Ram Power, Raser Technologies, Sierra Geothermal (Canada), U.S. Geothermal, Vulcan Power and Western GeoPower (Canada).

Enhanced geothermal systems (EGS) firms include AltaRock, Green Rock Energy (Australia), Panax Geothermal (Australia), Petratherm (Australia) and Potter Drilling. Leading technical and engineering consultancies and EPC contractors include AMEC, Enex (Iceland), GeothermEx, Geothermal Development Associates, Geothermal Resource Group, Horizon Well Logging, Hot Dry Rocks (Australia), Mannvit Engineering (Iceland), Ormat Technologies, Power Engineers, SAIC, SKM Consulting (Australia), West Japan Engineering Co. and Wood Group (United Kingdom)

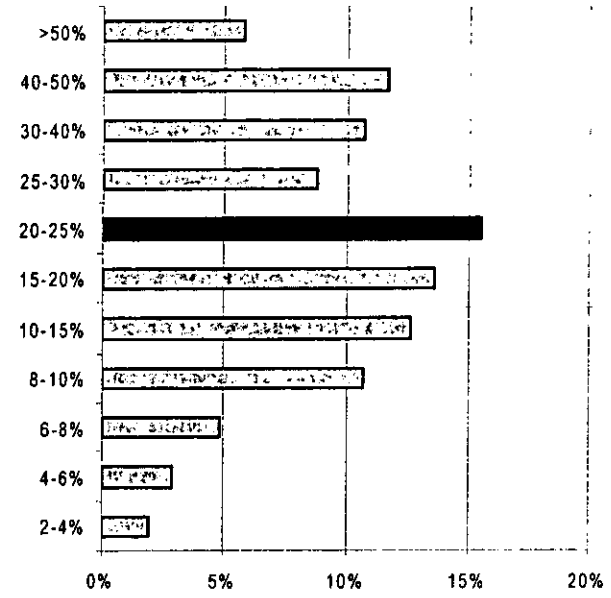
Leading drilling and drilling services companies include Baker Hughes, (United States), B.J. Services (United States), Boart Longyear (United States), Halliburton (United States), Iceland Drilling (Wales), Schlumberger (France, United States and The Netherlands), Thermasource (United States) and Weatherford (United States).

Percentage of U.S. Electricity Generation From Non-Hydro Renewable Sources in 2020



Source: Multiple CCBJ surveys with the same question conducted in 2008 and 2009 on the following topics: wind energy, CCS, snapshot and geothermal. Black bar indicates median range. Question was: U.S. DOE's Energy Information Administration says non-hydro renewable sources were responsible for 2.4% of U.S. electricity generation in 2006. What percentage of U.S. electricity generation do you believe non-hydro renewable sources will represent in 2020? (includes wood, municipal solid waste, landfill gas, sludge, biomass, geothermal, solar and wind).

Percentage of U.S. Electricity Generation From Non-Hydro Renewable Sources in 2050



Source: Multiple CCBJ surveys with the same question conducted in 2008 and 2009 on the following topics: wind energy, CCS and geothermal. The black bar indicates median range.

RPS expected to drive sustained growth from 2015-2020.

The global geothermal pipeline now exceeds 10 MW of projects under development, which if completed would almost double the installed global geothermal capacity of 10.5 GW built up over the past 30 years.

Currently, there are over 215 commercial geothermal electricity projects operating in 24 countries. The largest dry steam field in the world is The Geysers, 116 km north of San Francisco. The Geysers began in 1960 and has 1360 MW of installed capacity. **Calpine Corp.** now owns 19 of the 21 plants in The Geysers and is currently the United States' largest producer of geothermal energy. The other two plants are owned jointly by the Northern California Power Agency and the City of Santa Clara's municipal Electric Utility (now called Silicon Valley Power). Since the activities of one geothermal plant affects those nearby, the consolidation plant ownership at The Geysers has been beneficial because the plants operate cooperatively instead of in their own short-term interest. The Geysers is now recharged by injecting treated sewage effluent from the City of Santa Rosa and the Lake County sewage treatment plant. This sewage effluent used to be dumped into rivers and streams and is now piped to the geothermal field where it replenishes the steam produced for power generation.

Another major geothermal area is located in south central California, on the southeast side of the Salton Sea, near the cities of Niland and Calipatria, Calif. There were 15 geothermal plants producing electricity in the area. CalEnergy owns about half of them and the rest are owned by various companies. Combined the plants have a capacity of about 570 MW. The Basin and Range geologic province in Nevada, southeastern Oregon, southwestern Idaho, Arizona and western Utah is an area of rapid geothermal development. Several small power plants were built during the late 1980s during times of high power prices. Plants in Nevada at Steamboat near Reno, Brady/Desert Peak, now produce about 240 MW. As indicated on the chart on page 24, Nevada and Utah account for 86% of the new leases granted by the U.S. government in 2007-2008.

While geothermal electricity using existing technology indeed has good short-term prospects, the best sites are already snapped up. If geothermal is to make a big dent in renewables' inevitable penetration of the U.S. electricity business, EGS will have to play a role. Regardless, the manufacturers, consulting engineers, investors and policymakers in the CCBJ community believe that non-hydro renewables will account for roughly 8-10% of electricity by 2020 and 20-25% by 2050, according to compiled results of CCBJ surveys that incorporated the identical question (see charts above). How America reaches these thresholds remains to be seen, but it seems certain that there will be an ample supply of scientists, engineers, entrepreneurs, businessmen and corporations to chase the goal. ☼

Geothermal Developers Grapple With Financial Realities of 2009

For many geothermal power plant developers in North America, the worldwide economic free-fall that began in September 2008 has turned 2009 into a year of holding on, hunkering down and trying to survive. Despite holding leases to tens of thousands of acres of geothermal-rich land in the western United States, most developers lack risk capital to invest in the upfront geo-scientific work and exploratory drilling that is needed to verify the extent and quality of geothermal resources under the ground. (An exception to some degree is **Ormat Technologies**, which generated $252 million in revenues last year from its 505-MW portfolio of existing geothermal power plants; for more on Ormat see story on page 20.)

As recently as a year ago, developers could obtain debt financing before they had validated and drilled the production wells to tap geothermal resources—had "steam behind the pipe" in industry parlance. Not so today. "We've come out of a period in which there has been hyper-liquidity, a buyer's market for capital if you will. In the period we're in now, the pendulum has swung the other way," Ric Abel, Managing Director, Electric Finance Group, **Prudential Capital Group**, told CCBJ in April. "While in the past developers could get debt sooner in the life of a project and finance their drilling with a larger percentage of debt, today drilling and proving up the resource is seen as an equity risk."

Abel spoke at the March 2009 San Francisco Geothermal Innovation and Investment Forum sponsored by **Greenpower Conferences**. He was one of several representatives of lending institutions who discussed just how much financial conditions have tightened up for geothermal developers since the fall of 2008.

Investors had similarly bad news. Venture capitalists from **Google.org** and **KPCB** said they're only investing in technology firms with a strong upside potential, like those aiming to gain a position in the emerging enhanced geothermal systems (EGS) industry (also known as hot dry rock or HDR; for more, see feature on pages 29-31).

Private equity investors told the audience that because of the depressed market caps of publicly held geothermal developers, investors would prefer to buy geothermal companies or their operating power plants rather than invest in new geothermal projects. "Right now because of the large number of [geothermal] companies looking for financing as well as the significantly shrunken pool of available capital we expect that [development] deals will be few and far between going forward. The return hurdles and pre-requisites for successful private equity investment will be a lot higher," Paul Ho, managing director of **Hudson Clean Energy Partners**, told the audience.

New Wave of Developers

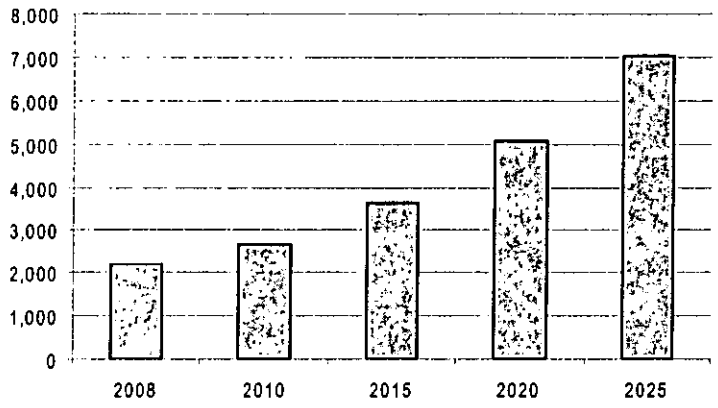
This was not news to the North American geothermal project developers who were in the audience, five of whom would later sit on a panel together representing their firms: **Magma Energy, US Geothermal, Ram Power, Nevada Geothermal Power** and **Sierra Geothermal Power**. These companies are part of a relatively new wave of pure-play geothermal project developers that emerged in this century, driven by the California energy crisis, the adoption of renewable energy standards in western states and the emergence of climate change and energy security concerns. Unlike Ormat and a handful of larger independent power producers and energy companies playing in U.S. geothermal project development—such as **CE Generation** and **Enel North America**—these firms are in the early stages of building their portfolios of geothermal projects. Tim Stephure, a geothermal expert at **Emerging Energy Research**, calls them "junior developers." Some have purchased existing plants with an eye toward expanding or repowering those facilities, but all are focused on new developments.

Hezy Ram, a longtime executive with Ormat who founded Ram Power last year, told an anecdote that while not literally true was nonetheless emblematic of the state of play for him and his counterparts. After leaving a meeting with an investor, he checked the visitor register at the front desk. Competing developer Doug Glaspey of U.S. Geothermal had been in just before him, while Brian Fairbank, CEO of developer **Nevada Geothermal Power** had just arrived for his appointment. (Both Glaspey and Fairbank were on the conference panel.) "We all go to the same private equity funds and financial institutions and talk to the same people," he said. "We need development capital. And as you know capital is very scarce today."

Development capital—lots of it—is needed for the upfront work that developers must do not only to verify that adequate geothermal resources lie under the ground they've leased or purchased, but also to sink wells accurately enough to tap those resources. In this economic environment, until they've got "steam behind the pipe," they can't access private equity funding, tax-credit equity or project-finance debt. And even when they can meet the risk requirements of such funders, funding is harder and more expensive to obtain than any time in recent memory.

As Abel pointed out, prior to the recession, developers could often obtain debt financing for some of this risky resource development activity. Not only is that no longer the case, but prospective equity investors are requiring more resource development work—more steam behind the pipe—before they'll invest in projects. And lenders are requiring higher levels of equity investment before they'll lend money for a project. One geothermal

Forecast of US Capacity for Conventional Hydrothermal Power



Source: CCBJ 2009 Geothermal Survey conducted in April 2009. Question was: Geothermal generating capacity in the United States was approximately 2,200 MW at the end of 2008. Given an economic revival by 2010 and adequate incentives, please estimate the US capacity for conventional hydrothermal power for 2010, 2015, 2020 and 2025. Result displayed is an average of the responses written in.

veteran who spoke to a CCBJ editor at the conference said: "The big economic problem affecting us now is the amount of debt you can get as part of your total project cost. This amount used to be 70-80%, and you'd only have to come up with 20-30% equity. First of all, nobody is really doing any deals right now. Banks don't have money they're willing to loan on such projects. But the numbers we're hearing tossed around [by lenders willing to lend] are more like 40-50% equity."

Panelists agreed that the last significant geothermal financing deal in the United States was Nevada Geothermal Power's $180 million line of credit to build a 50-MW project near Winnemucca, Nevada. But as CEO Brian Fairbank told CCBJ in an interview, the financing was much less favorable than what the company had anticipated. And in the current climate, the developer's success in getting steam behind the pipe for 50 MW has not led to any breakthroughs in financing an additional 50 MW at the same site. "Just at the time when we should have the light of success shining on us, we've run into the collapse in the credit market and a situation where the equity markets aren't working very well either." (For more on Nevada Geothermal Power, see page 28.)

Geothermal Land Rush

Before a developer worries about financing, however, it must have land leased for development, either from private owners, states or the federal Department of Interior, which controls through the **Bureau of Land Management** (BLM) millions of acres in the West. After May 2007, when the BLM finalized its rules for auctioning leases under the Energy Policy Act of 2005, there was a "land rush" as firms bid for favorable parcels. Auctions in 2007 brought in bids ranging from an historic high of $14,000 per acre for a 470-acre parcel adjacent to The Geysers in California to bids in the neighborhood of $300 to $500 per acre in Nevada, according to a BLM news release. Data compiled by Emerging Energy Research shows that since 2007 the three top lessees are Ormat, with about 150,000 acres; **Raser Power Systems** with some 75,000 acres; and Magma Energy with about 45,000 acres. These three are followed by some 20 developers with anywhere from a few hundred acres to 20,000-plus acres under lease. (See chart on page 24.)

The BLM has been paid more than $63 million for geothermal leases since 2007, according to Kermit Witherbee, national geothermal program manager for the agency. According to Witherbee, the perceived value of auctioned leases have dropped significantly. In the agency's last auction in December 2008, the average price was between $30 and $50 per acre.

For developers without existing leases or rights to private or federal lands, the prospects of gaining a toehold in geothermal development are increasingly slim. Most of the favorable geothermal sites—outside of off-limits areas like Yellowstone National Park—have already been developed or acquired. "Those of us who have been around for a few years kind of got the first pick on some of these prospects that that [already] had drilling [done] and had discoveries," said Doug Glaspey, CEO of U.S. Geothermal. "Those are the sites we went to first, and those are rapidly being consumed not only by ourselves but by new entrants in the market. So the quality of [geothermal site] prospects is going down. That means the risk to define and develop new resources is going higher and higher."

Drill, Baby, Drill (With DOE Money?)

While the output of wind, solar PV, biomass, hydropower and other renewable power plants can be predicted with a fair amount of certainty, geothermal developers face much more uncertainty as they search for steam supplies anywhere from 2,000 to 10,000 feet underground.

To find geothermal resources of sufficient enthalpy (heat energy) for power generation, they start with geological mapping that points to likely areas. They also consider distance to grid connections. Then they hire staff or consultants to perform geochemical analyses of hot springs and geophysical analyses such as seismic studies to refine models of likely resources. On many prospective geothermal properties, developers have the benefit of earlier explorations done by oil and gas companies that were investigating geothermal in a big way in the 1970s and 1980s.

Many of those prospective sites were not developed because the market drivers of that era diminished with the decline in oil prices. Additionally, the binary technology that can utilize lower-temperature geothermal resources was not available on a commercial scale at that time.

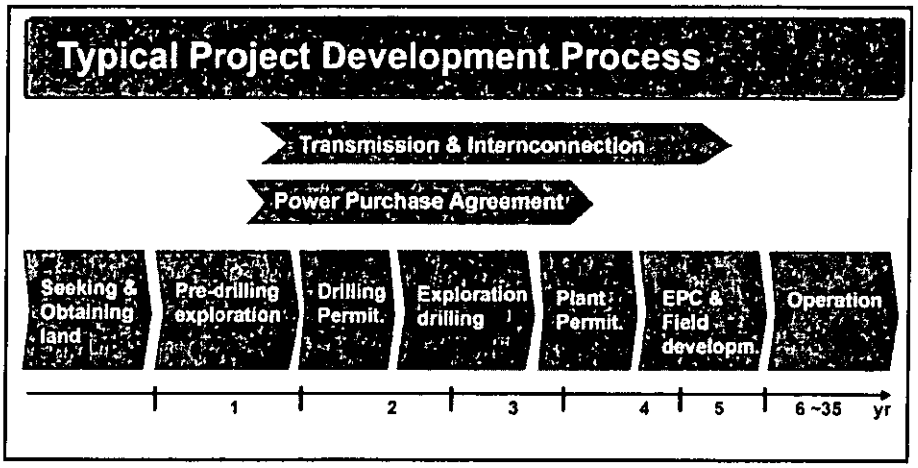
The costs for the geologic mapping, geochemical and geophysical work is generally in the hundreds of thousands of dollars for a 40 to 50 MW geothermal power project—add in permitting for the well drilling phase and you're looking at $2 million to $3 million, according to Brian Fairbank of Nevada Geothermal Power (see page 27).

Then the cash really starts to flow. Developers hire drilling contractors who come with rigs, equipment and personnel and charge $25,000 a day or more. Sometimes a drilling program start with slimhole test wells that can cost $2 million to $3 million each; in other cases developers and their contrators go straight to the production wells that can cost anywhere from $3 million to $10 million or more.

Like wildcat oil drillers, the geothermal prospectors are usually looking in areas without a history of geothermal production. They don't always hit paydirt, yet the drilling contractors must be paid. In fact, drilling "dry holes" is quite common. Developers estimated the risk at 20% to 30% on greenfield projects that haven't already been subjected to some exploratory drilling. "That scares a lot of people," said Glaspey.

"The drilling is really the wild card in geothermal," said Gary Thompson, CEO of Sierra Geothermal Power in response to a questions about average costs for developing a geothermal wellfield. "You have to have a fairly large contingency when you're talking about drilling because [the costs] are all over the map It could be $2 million, it could be $15 million to drill one of these wells. And your output varies [on the the same scale]. It could be two megawatts per well or 10 or 15 megawatts per well."

Typical Geothermal Project Develoment Process



Source: Geothermal Development in Emerging Markets by Rahm Orenstein, Ormat Technologies, Inc. Geothermal Innovation & Investment Conference, March 24th, 2009.

Given the risks of hitting dryholes and creating wells that produce less power than anticipated, the typical upfront capital required for a geothermal project of 40-50 MW with a typical life cycle of 30-35 years could be from $30 million to $50 million, according to developers. With the high risk profile of their endeavor and the difficulty of financing such activities, developers and other speakers at the conference pleaded with one particular person in attendance: Ed Wall, manager of the **U.S. Department of Energy's Geothermal Technologies Program.** What they asked for repeatedly is for Wall to use some of the $400 million for geothermal contained in the American Recovery and Reinvestment Act (ARRA) stimulus package to help developers mitigate this daunting dry-hole risk (see list on page 17).

"It's great to spend money on EGS. That's the future," said Glaspey. "But if you want megawatts on the ground today, you have to capitalize exploration. The way you do that is put it into drilling programs. Cost share [from the DOE] would be very nice for folks like us."

"There's a tremendous amount of conventional geothermal projects out there that desperately need assistance in order to do the drilling," said Abel from Prudential. "I think from a stimulus bill perspective, getting projects built, producing electricity and creating those jobs is where there's more bang for your buck."

Another option for DOE funding, according to Glaspey, is the loan guarantee program for renewable energy technology funded to the tune of $6 billion by the ARRA. "It may be possible for DOE to offer us loans at 3.5-4% interest," he said. "That's very encouraging, although we can't wait two years to get that kind of financing package," he added, referring to DOE's past difficulties with the loan guarantee program.

Long-Term Drivers

Despite the current difficulties, geothermal developers are operating in a marketplace with some very strong long-term drivers. Regardless of what happens with federal renewable energy standards and climate change legislation, utilities in western states are already under state laws requiring sharp increases in renewable generation. Because of its reliable baseload properties—in contrast to the intermittency of wind and solar—utilities and grid operators can more easily incorporate geothermal generators.

Those "junior developers" who can hang on through this difficult period will likely enjoy a more robust market envi-

ronment within one to two years. Prudential Capital Group's Ric Abel pointed out at the March conference and in a separate interview with CCBJ that institutional lenders like insurance companies still have a large appetite to finance long-term projects like geothermal power plants built with fixed-price EPC contracts and 20-year power purchase agreements. "There is money available, although it's a lot more expensive than it was a year ago," said Abel. "While drilling and proving up the resources is an equity risk, building the power plant and producing electricity for a PPA is more of a debt risk."

Abel said geothermal projects are financed in similar fashion to combined cycle gas turbine plants and other fossil fuel-fired power plants, with a waterfall structure designed to ensure that asset maintenance—including reservoir maintenance in the case of geothermal—is adequately funded and creditors are paid before plant equity owners. "This structure was developed and perfected primarily with gas-fired projects.... Most of the major law firms that focus on project finance are very familiar with this structure and the documents associated with it. At various times, including in the recent period of hyper-liquidity, people have deviated from that structure, but now the pendulum has swung back and lenders are approaching power projects in this more standard format."

For geothermal projects, a "disciplined operating budget" to maintain reservoir viability is critical to giving long-term lenders assurance. "You've got to have continued funding to maintain the geothermal resource, which is your fuel supply, on an ongoing basis," he said.

Emerging Energy Research's Stephure points to some recent investment highlights that show the underlying strength of the geothermal segment, but also point toward consolidation trends. He noted that Canadian energy company AltaGas recently purchased a 25% stake in

Leading Geothermal Power Market Participants

Power Plant Owners & Developers

Major IPPs And Utilities:
ArcLight Capital Partners
Calpine (USA)
Chevron (USA)
EnBW (Germany)
ENEL (Italy)
Geysir Green Energy (Iceland)
LaGeo (El Salvador)
Mid-American/CalEnergy (USA)
Mighty River Power (New Zealand)
Ormat Technologies (USA)
PNOC EDC (The Philippines)
Terra-Gen Power (USA)

Pure-Play Geothermal Developers:
Magma Energy (Canada)
Nevada Geothermal Power (Canada)
Polaris Geothermal (Canada)
Ram Power (USA)
Raser Technologies (USA)
Sierra Geothermal (Canada)
U.S. Geothermal (USA)
Vulcan Power (USA)
Western GeoPower (Canada)

Power Plant Equipment Suppliers:
Alstom (France)
Ansaldo Energia (Italy)
Fuji (Japan)
GE/Nuovo Pignone (USA)
Mitsubishi (Japan)
OAO Kalugo Energo (Russia)
Ormat Technologies (USA)
Siemens (Germany)
Toshiba (Japan)
Turboden (Italy)
UTC/Pratt & Whitney (USA)

Energy Conversion Technology Developers
Borealis/Power Chips (Gibraltar)
ElectraTherm (USA)
Exorka (Germany)
O-Flex
Ormat Technologies (USA)
Turbine Air Systems (USA)
UTC/Pratt & Whitney (USA)

Technical and Engineering Consultancies & EPC Contractors
Amec (USA)
Enex (Iceland)
GeothermEx (USA)
Geothermal Development Associates (USA)
Geothermal Resource Group (USA)
Horizon Well Logging (USA)
Hot Dry Rocks (Australia)
Mannvit Engineering (Iceland)
Ormat Technologies (USA)
Power Engineers (USA)
SAIC (USA)
SKM Consulting (Australia)
West Japan Engineering Co.
Wood Group (United Kingdom)

Drilling And Drilling Services Firms
Baker Hughes (USA)
B.J. Services (USA)
Boart Longyear (USA)
Halliburton (USA)
Iceland Drilling (Wales)
Schlumerger (France, USA, Netherlands)
Thermasource (USA)
Weatherford (USA)

EGS Developers/Technology Firms
AltaRock (USA)
Geodynamics (Australia)
Green Rock Energy (Australia)
Panax Geothermal (Australia)
Petratherm (Australia)
Potter Drilling (USA)

Source: CCBJ, EER, NEF and Geothermal Resources Council

Magma Energy and Raser Technologies has recently executed a funding agreement with **Copper Canyon Mining**. Australian EGS geothermal developers **Geodynamix** and **Petratherm** have formed alliances and joint ventures with very large companies: Geothermix with Indian conglomerate **Tata** and Petratherm with Australian utility **TruEnergy** and oil & gas producer **Beach Petroleum**. "Companies with bigger balance sheets will be better positioned moving forward," said Stephure.

"There are definitely some opportunities for these players to take advantage of the economic situation. They can fund a lot of activity in house and pick up projects from developers who are struggling. M&A activities are likely to occur. We may also see utilities move into this space, either developing or owning their own projects or partnering to help develop projects." In chaos lies opportunity is how some observers are characterizing 2009 and the geothermal industry has both. ☼

Geothermal Power in Developing Countries

With the best geothermal resources located along the Pacific Ring of Fire, there are enormous opportunities for developing geothermal power in Asian and Latin American countries that currently have little or none. The eastern and southern Mediterranean and the East Africa Rift zone (Kenya, Ethiopia, etc.) also present large geothermal development opportunities.

But developing geothermal power plants in many emerging markets is an enterprise fraught with high risks—risks that are layered on top of the ordinary risks of hitting dryholes and drilling under-producing wells that confront geothermal project developers in the United States and other developed countries. To build geothermal wellfields and power plants, most developing countries (the exceptions being the Philippines, Mexico, El Salvador and Indonesia) need foreign experts, suppliers and development capital because they lack the internal capacity—yet foreign firms often find it difficult to work in many developing countries because of the lack of frameworks to manage risks, delays in administrative processing, frequent requests for local patronage, contracts being violated and projects being shut down for murky political reasons.

"In some of these markets you have to add political risk to the drilling risks and credit risks that exist in developed countries," said Rahm Orenstein, director of business development for internationally active **Ormat Technologies** in a talk at the March 2009 Geothermal Innovation and Investment Forum sponsored by **GreenPower Conferences** in San Francisco. "Then you have off-take risk. In some countries, there's a high risk that your electricity customer won't pay you."

Poor market conditions are also a barrier to geothermal development in many developing countries. These include: Electricity markets that have not been fully restructured to encourage competition by independent power producers (IPPs), low rates for electricity that price geothermal out of the market, and lack of incentives to subsidize the up-front investment costs of geothermal power projects. "In many countries, geothermal has to compete with fossil fuels that still get subsidies and incentives," explained Orenstein. Additionally, many developing countries that have restructured their state power monopolies to facilitate more competition still retain monopolistic elements. "Any place we go and compete as an IPP is a market that has been deregulated to allow merchant power suppliers like us to compete, which is good.... But in some cases we discover that market is still to some extent monopolistic. Utilities may have been broken into a generation company and a transmission and distribution company, so now they have two monopolies."

For developing countries desperate for more domestic power sources—and for the worldwide effort to mitigate carbon emissions—the consequences that these risks and barriers will forestall geothermal power development in emerging markets are immense. **West Japan Engineering Co.** (West JEC), which has extensive experience in Central America, estimates that 3,000 MW to 4,000 MW—about 10 times current installed geothermal capacity—of new geothermal could be developed in that region given proper market structures, incentives and policies.

Geothermal-rich Indonesia has set a goal of building more than 4 GW of geothermal power capacity by 2014 (It currently has less than 1 GW online), but many international companies are reluctant to work there because of its unfavorable power market, bureaucratic inertia and reputation for corruption. In Kenya, some 4 GW of geothermal capacity—triple the nation's current electrical generation capacity—could be developed in the Rift Valley given proper market conditions and incentives, according to a study by UN agencies and the national power generation utility.

Foreign firms have successfully developed geothermal power projects in all of these regions and other developing nations. But it hasn't been easy.

Case In Point: Kenya

Ormat began developing a geothermal project in Kenya in the late 1990s, soon after the former state-owned power monopoly was unbundled into generation and transmission-distribution units. "Kenya was still heavily reliant on several hydropower projects for its electricity generation, and in the late 1990s the country suffered a major drought that caused generation to drop by some 30 percent," said Orenstein. The reliable baseload characteristics of geothermal made it an ideal resource for the country's power needs, according to Orenstein.

A **World Bank** supervised international competitive bid was issued by the utility, which was won by Ormat. Nine months after signing of a 30-year 50 MW power purchase agreement (PPA), the first 8 MW plant came online, and was soon expanded to 12 MW. By May 2002, Ormat had completed and demonstrated a total of 48 MW of steam capacity from the wells, but then it had to wait an agonizing six years to wade through what Orenstein called "administrative and political issues" before it could complete its power plant to reach that capacity. Ormat invested $150 million of its own funds for the wells and the plant; only recently was it partially refinanced by a loan from the German DEG lead consortium.

Kenya has relatively high electricity tariffs—between $80 and $120 per MWh compared to $60 to $80 for the rest of sub-Saharan Africa, according to a report by Julie Rowlett of the **Columbia University School of International and Public Affairs**. So Ormat's wholly owned Kenyan

subsidiary OrPower is likely doing well. But according to Ormat's 2008 annual report, the firm, along with the handful of other IPPs operating in Kenya, is under pressure to reduce tariffs to allow the government to make good on campaign promises of cheaper electricity. Furthermore, its customer **Kenya Power and Light Company** is being re-organized. And the country is in a state of ongoing political turmoil between President Mwai Kibaki and Prime Minister Raila Odinga.

To manage the risks of operating in countries like Kenya, Ormat buys political risk insurance from the **Multilateral Investment Guarantee Agency (MIGA)** of the **World Bank Group** or from **Zurich Re**, for most of its foreign projects, according to the company's annual report.

Ranking Developing Country Markets

Research outfit **New Energy Finance** has ranked the favorability of geothermal markets in both developed and developing countries. NEF's four criteria are:

Stability – political, economic and social, including a reliable electricity grid.

Availability of **local partners** to handle licensing, permitting and obtaining power purchase agreements.

A positive **policy framework** with high energy demand and limited supply

Incentives or subsidies such as feed-in tariffs, renewable energy certificate trading schemes and tax exemptions.

Global Geothermal Markets Rating

Country	Stability	Local Partners	Policy Framework	Subsidies	Ranking
Chile	+	+	+	+	4.0
Greece	+	+	+	+	4.0
Hungary	+	+	+	+	4.0
Iceland	+	+	+	+	4.0
Australia	+	+	+	+	4.0
Austria	+	+	+	+/-	3.5
Slovakia	+	+	+	+/-	3.5
Nicaragua	+	+	+	-	3.0
US	+	+	+	-	3.0
Guatemala	+	+	+	-	3.0
Indonesia	+	+	+	-	3.0
Japan	+	+	+	-	3.0
Philippines	+	+	+	-	3.0
Germany	+	+	+	-	3.0
Italy	+	+	+	-	3.0
New Zealand	+	+	+	-	3.0
Turkey	+	+	+	-	3.0
Costa Rica	+	+	+/-	-	2.5
El Salvador	+	+	+/-	-	2.5
Poland	+	+	+/-	-	2.5
Portugal	+	+	+/-	-	2.5
China	+	+	+/-	-	2.5
Thailand	+	+/-	+	-	2.5
France	+	+/-	+	-	2.5
Kenya	+/-	+	+/-	-	2.0
Mexico	+	+/-	-	-	1.5
Russia	+	+/-	-	-	1.5
Ecuador	+	-	-	-	1.0
Peru	+	-	-	-	1.0
Papua New Guinea	+/-	+/-	-	-	1.0
Djibouti	+/-	+/-	-	-	1.0
Ethiopia	+/-	+/-	-	-	1.0

Source: New Energy Finance. Countries were ranked on a scale of 0 to 4 points. Each of the criteria presented in the four columns is worth 1 point. A + symbol signifies that country fully meets the criteria and 1 point. A +/- symbol indicates that a country only partially meets the criteria and is awarded a 0.5 point.

West JEC would probably add to that list a wholesale power market that is amenable to power purchase agreements (PPAs). Without PPAs, geothermal plants compete as merchant power producers, being dispatched only when their power is needed and their price is competitive. "Not all countries are like the United States where you can get PPAs," said Enrique Lima, general manager for overseas business. "In Central America, for example, it is difficult to get PPAs. You have to compete in the market where the price varies 24 hours a day. It can go from as low as 1 to 2 cents and as high as 10 to 13 cents at peak. But the duration of the peak is very short, so the average price you'll get is 3 or 4 cents. This makes it very difficult for geothermal to compete."

It's no suprise that Kenya is near the bottom of NEF's rankings with a 2.0 ranking out of 4.0 possible points. (See chart on left for all of NEF's rankings.) Many developing countries rank more highly, in NEF's view, including Chile, Hungary, Nicaragua, Guatemala, Indonesia, the Philippines and Turkey.

Indonesian Puzzle

But according to New Energy Finance Associate Mark Taylor—and research by CCBJ's parent company **Environmental Business International (EBI)** on behalf of the Organization for Economic Cooperation and Development—the level of risks and difficulties presented by certain countries can be as much a matter of perception or opinion as fact. Indonesia, for example, is widely perceived as a very difficult market to develop geothermal projects due to broken contracts, turgid bureaucracies, an unfriendly power market and corruption. According to an executive with an international engineering firm active in geothermal worldwide, wholesale power prices in Indonesia are tied to the price of coal power, essentially pricing geothermal out of the market. This individual (who was interviewed confidentially for EBI's OECD study) doesn't believe

that the government's plan to offer higher rates for geothermal and other renewables will succeed because of resistance within the electricity bureaucracy.

WJEC's Lima offered a more balanced perspective on Indonesia, telling CCBJ: "The Indonesian government is now thinking what kind of support is needed for geothermal and other renewables but they have not yet reached a conclusion." And Taylor says he has "talked to people who have developed projects there, and they say that if you know the people and the culture, it's not that bad." Indeed, **Chevron**, which calls itself the largest producer of geothermal energy in the world, has a 30-year history of geothermal work in Indonesia (through **Unocal** which Chevron acquired in 2004). According to Taylor, government officials in charge of boosting geothermal production to 4.4 GW by 2014 are aware of its reputation and working to ease some of the barriers and challenges.

A key insight that emerged from EBI's research is that some firms succeed handsomely in doing business in foreign markets where others fear to tread. One wind power developer told EBI that his firm avoided mature wind-power markets in OECD countries to focus on the opening markets in what he called "dodgy" countries with higher levels of political risk and corruption. While some firms reported avoiding China because of intellectual property risk and poor contract enforcement, several European wind power firms work quite successfully in China. It appears that a market which scares off some firms can offer opportunities to other firms that adapt to the country's business norms and market conditions.

For geothermal power developers, however, the higher levels of risk and difficulty imposed by operating in a "dodgy" country are much more formidable than for wind power because of the cost of quantifying and developing resources. While assessing the expected annual yield of a wind farm site is not a trivial matter, doing the drilling needed to prove and develop the geothermal resource for a 50-MW power project can run as high as $50 million or more.

Governments, Funding Institutions Step Up

Because of these high costs and the attendant risks of finding dryholes or hitting reservoirs with lower than expected power capacity, geothermal power development in emerging markets is often too risky for the private sector to do on its own. To offset these costs and risks, developed country governments, multilateral lending agencies like the World Bank and in some cases host country governments subsidize the exploration and resource development phase of creating a new geothermal power plant.

The impact of such subsidies can be seen in the contrast between the geothermal power development trajectories of the Philippines and Indonesia. The two countries are both rich in geothermal resources and both began developing them in the 1970s, yet the Philippines today has about 1900 MW of capacity online, meeting about 17% of total demand, while Indonesia has less than 1 GW meeting 5% of demand. According to multiple informants for EBI's OECD research, the Philippines' success story was based on a policy in which publicly owned **PNOC Energy Development Corporation (EDC)** took the exploration and drilling risk, selling steam to power plant developers.

By contrast Indonesia required foreign developers to fund exploration and drilling. "In the 1990s, you could do a geothermal power project in the Philippines for 4.5 cents to 5 cents U.S. per kilowatt-hour, but contracts in Indonesia were at 7.5 to 8 cents because developers were putting a big margin on for the risks being assigned to the projects," said EBI's source with the international engineering firm. (PNOC EDC has since been privatized and EBI's sources say the industry is watching closely to see how its development policies evolve.)

Looking forward, Taylor says that funding to underwrite the costs of resource exploration and wellfield development will be vitally important to building geothermal projects in most developing countries. "Right now, developing geothermal in these countries is so high-risk that there needs to be some sort of multilateral bank or government intervention to help out," he said.

He spoke recently with the head of the World Bank's $25 million GeoFund which subsidizes drilling and exploration and technology development. The official reported that the fund had lent $5 mil-

Developing Markets with Most Promise in Geothermal

- Brazil
- Canada (2 responses): political stability, history of resource development
- Chile (2 responses): resource and government support, great resource, new developers in area
- China (2): Universal carbon tax
- Iceland: size of resource
- India: universal carbon tax
- Indonesia (4) : lots of resources
- Japan
- Kenya
- Mexico
- Nevis Island (Antilles): great start, high electricity pricing
- Nicaragua: good resource
- Philippines (5): replace dependance on diesel powered generation; size of resource
- Turkey

Source: CCBJ 2009 Geothermal Survey conducted in April 2009. Question was: Many regions of the developing world such as Central America and parts of Africa have tremendous potential to develop more geothermal power, yet little internal capacity to develop their resources. In many cases, such countries present high risks for foreign geothermal developers and service providers. Please note the three developing countries that you think will grow their geothermal power capacity the most over the next 10 years and what factors will make those markets favorable for geothermal development.

lion and still had another $20 million to lend, which would likely go to subsidize three resource exploration efforts and five technology development programs. "The European Investment Bank and the European Bank for Reconstruction and Development have also offered funding, but the existing financing resources are absolutely not enough. To significantly ramp up geothermal power capacity in developing countries, it will be necessary for multilateral banks to step up their financing."

Enrique Lima of West JEC told CCBJ about a series of geothermal projects in countries such as the Philippines, Indonesia, Guatemala, Jordan, Panama, Colombia and other countries for which the initial stage of development were or are being financed by country-to-country development assistance programs. "This kind of financing through donations or soft loans may provide means to offset risk," said Lima.

Chile, Turkey, Hungary Entice Developers

According to Taylor, a country that has been particulary successful in turning around a negative reputation for geothermal development is Chile. Developers were plagued by long delays in receiving permits until the government streamlined the permitting by setting deadlines for administrative departments.

"Chile is one of the best markets now for two reasons," said Taylor. "It doesn't have a feed-in-tariff but it has an average wholesale electricity price of $115 per megwatt-hour, which is very high. The other reason is that it has an immense geothermal resource and developers who have looked at it are fairly confident that they can make projects work economically." The Chilean government is also offering a $5 million subsidy per geothermal project and is doing organized leasing and tendering of known geothermal resource areas.

"Many mining companies up in Northern Chile need a lot of electricity, and they're paying high rates for it," said Taylor. "There is a lot of geothermal [in the mining areas], with geysers and other surface expressions." Combining small distributed projects for mines and other remote industries with utility-scale projects, Chile can develop 2350 MW of geothermal power capacity according to an estimate provided by NEF from Bob Lawrence & Associates, a consulting firm.

Other developing-country markets have implemented feed-in-tariffs for geothermal, according to Taylor. These include Hungary with a $90 per MWh rate; Turkey with $70 per MWh; and the Central American Electrical Interconnection System (SIEPAC) linking Panama, Costa Rica, Honduras, Nicaragua, El Salvador, and Guatemala has set an $80 per MWh FIT (SIEPAC is still under construction as of April 2009). ☼

Trouble In Central America: One Company's Experience

CCBJ's parent company Environmental Business International (EBI) recently conducted a series of confidential interviews with geothermal market participants on behalf of the Organization for Economic Cooperation and Development to assess the market barriers in different countries. EBI's informants (interviewed confidentially) told stories of extra costs, obstacles and delays due to government procedures and local business culture. One of the most daunting experiences was related by an international developer doing its first project in Central America. As a result of these experiences, the company will raise its revenue requirements for future projects in the country by 10% to 20%. (The country is not identified to protect the company's confidentiality.) Among the challenges:

* A government anti-corruption law made customs clearance cumbersome and expensive. A mistake like classifying a pipe fitting as a pipe could result in fines and special treatment of all the company's imports for a year.

* Conflicts between labor unions in Mexico and Central America resulted in a *de facto* ban on Mexican trucks crossing the border. In spite of a regional free trade agreement, shipments are re-loaded at the border—a requirement that could not be safely met for a 50-ton heat exchanger the company was importing. A logistics contractor had to negotiate a special arrangement with the unions.

* The company had difficulty importing the isopentane needed for the binary steam cycle because customs officials didn't know how to classify it.

* Banking regulations prevented the company from opening an account unless it established a domestic company. This meant that the company could not establish credit at local vendors and had to get quotes, write purchase orders and process invoices through its home office for all purchases.

* The project tender document gave the client—a quasi-public utility—the right to travel at the developer's expense to inspect the production of components. While traveling to inspect heat exchanger or turbines was justifiable, client staff insisted on traveling to visit the makers of commodity items like transformers and pumps.

* For some site preparation work, the company was forced to employ laborers instead of heavy equipment.

* After a site engineer was murdered, the company hired an armed security service to accompany all foreign staff 24 hours a day.

ARRA Update: Federal Procurement Picks Up at GSA, DOD and DOI

Federal government agencies are flush with cash to spend quickly thanks to the American Recovery and Reinvestment Act (ARRA), also known as the Stimulus Package. And a great deal of that cash will go to services and products related to energy efficiency and renewable energy projects. While the U.S. Department of Energy (DOE) is the largest recipient and disburser of ARRA funds for energy efficiency and renewable energy, other federal, state and local agencies also have a great deal of new money to spend on these segments by September 30, 2010.

As noted in our first edition of 2009 (January/February/March 2009), given the size and the phased implementation of the ARRA, CCBJ will cover aspects relevant to our readers over several editions in 2009. In this edition, we focus on federal procurement for services and products associated with energy efficiency and renewable energy by three federal agencies: **General Services Administration** (GSA), **Department of Defense** (DOD) and **Department of Interior** (DOI).

According to CCBJ's estimates, these three agencies will directly spend about **$5.5** billion on contracts for renewable energy and energy efficiency projects by September 30, 2010. (Note: this does not include funds being channel to states, local governments, housing authorities, tribes and school districts by the **Department of Education, Environmental Protection Agency, Housing and Urban Development** and DOE.)

Five and a half billion dollars is a rough estimate based on an educated guess about the amount of capital project funds that GSA, DOD and DOI agencies will spend on energy-related projects. Congress gave the agencies wide latitude, telling the Army, for example, to spend **$1.47** billion to "improve, repair and modernize... facilities, restore and modernize real property to include barracks, and invest in the energy efficiency of ... facilities." All other DOD departments, including reserves, received similar marching orders. Similarly, the **Bureau of Land Management, Fish and Wildlife Service** and other DOI agencies have been given money for "repair of roads, bridges, property, and facilities and for energy efficient retrofits of existing facilities."

With that kind of discretion, the full scope of GSA, DOD and DOI spending on energy efficiency projects like upgraded lighting and replacement of inefficient HVAC equipment and renewable energy projects such as solar water heating systems and wind turbines won't be known for some time. But early indications are that spending from DOD at least will be very robust.

In a March 2009 report to Congress, DOD highlighted hundreds of energy efficiency and renewable energy projects that will be funded with ARRA money. Just a few examples: **$4.7** million for wind turbines at the **Air Force's** Cape Newenham Long Range Radar site in Arkansas; **$10.7** million for a PV system at Camp Pendleton Marine Corps Base in California; and **$3** million to upgrade the HVAC system at Fort Leavenworth in Kansas.

Obviously, there's a lot of work on tap for equipment installers and integrators and engineering and construction firms. But DOD is also looking for consultants to do conceptual planning and analysis work. A whole section of ARRA DOD funding is devoted to research, development test and evaluation (RDT&E) projects, and DOD aims to spend much of that funding on energy related projects.

There are initiatives around designing more fuel-efficient military vehicles and developing renewable energy generation and energy devices for combat usage; contracts for those types of projects will prob-

Recommendations for DOE for Utilization of the $400 million in ARRA or Stimulus Funds for Geothermal Energy

Reduce drilling risk
Fund Exploration and Drilling
Incentives for exploration
Invest in exploration research
Create new test wells for deeper operations
Help finance geothermal development first cost
Construction loan capital for shovel-ready developments
Continue and Increase Loan Guarantees
Staff Up to Process Loan Guarantee Applications
Reduce development red-tape
Facilitate and ease permitting process
Concentrate on Hot Dry Rock Geothermal Energy
Invest in proving EGS technology
Fund EGS developments
Fund traditional deployment instead of EGS
Don't squander it on EGS
Invest in geothermal R&D
Advance hard-rock drill-bit development
Invest in cycle engineering and simulation
Advance hybrid solar/binary power plants
Fund new research for power conversion technology

Source: CCBJ 2009 Geothermal Survey conducted in April 2009. Question was:What three top recommendations would you give to US DOE for the $400 million it received in the American Recovery and Reinvestment Act (ARRA) specifically for geothermal.

ably go to firms' with prior experience in combat and weapons systems. But there are also RDT&E projects suitable for consulting engineering firms with expertise and capabilities in designing building energy systems. For example, the Army is looking to spend $3 million for planning of an ultra-low energy campus that can be a model for other facilities. The Navy and Marine Corps expect to spend $2.5 million on developing methods to integrate cogeneration into tactical systems. And the Air Force is in the market for ideas to maximize renewable energy development on its vast test ranges.

According to Chris Lippert, corporate initiative leader for energy efficiency at $2-billion consulting engineering firm **Tetra Tech**, federal agencies have pent-up demands for energy efficiency and renewable energy projects—demands that are finally being satisfied with ARRA funding. "DOD and all federal agencies have been under some form of federal mandate to reduce energy use for some time," said Lippert, citing the Energy Policy Act of 2005 and the Executive Order 13423 signed by former President George Bush in 2007. "But these mandates have not traditionally come with funding. Now that the stimulus package has made funds available, federal agencies are well positioned to implement a large wish list of projects to cut energy use and save on energy costs. There's a great opportunity for the private sector to provide those services."

While many businesses can become federal contractors, given the rigid timelines for spending in the ARRA, Lippert and others think that the vast majority of spending will go to existing contractors. "Existing contract vehicles are incredibly important," he said. "The contracting staff on the federal side is already overtaxed and now they're being asked to take on this significant chunk of work."

That doesn't mean that only those already in the federal doorway need apply because there is great scope for subcontracting work. In demand will be installers and integrators of renewable energy and energy efficiency equipment and projects, but also consulting firms with relevant expertise.

According to Lippert and other executives familiar with federal contracting, becoming a subcontract supplier to a federal contractor is not all that difficult. "As long as you can prove you have your relevant licensing, such as a plumber's license for installing solar water heating, you can start on day one," said Scott Sklar of the **Stella Group**, a firm that integrates solar, wind, geothermal and other renewable energy sources for public and private sector clients. "You may have to get some additional bonding and insurance."

Where to Find Opportunities

Sklar, Lippert and others agree that the best places to start looking for federal subcontracting opportunities are the federal websites, particularly GSA.gov and FedBizOpps.gov. "You have to take the time to troll through and look at all the opportunities," said Sklar. "The U.S. government is the biggest user of energy in the world and the biggest owner of buildings. I suggest focusing on the niches where you are most capable.... You may have done a lot of medium-sized business renovations and now you want to install solar systems for medium-sized buildings. Well, that's different from doing a giant base dormitory that is six square blocks. Focus on what your experience level is and look at the government through that lens."

Sklar takes note that energy efficiency and renewable energy contractors may be able to find significant opportunities with some of the 16 energy service companies (ESCOs) designated as primary energy service performance contractors by DOE in December (see list above). CCBJ's conversations with a couple of these entities indicate that they anticipate being in the market subcontracting vendors, but their needs are probably more skewed to implementation rather than planning and analysis. (Funding for many of these projects is not tied to ARRA but rather to cost savings achieved by energy conservation measures; CCBJ will cover ESCOs and energy service performance contracting in our upcoming edition on energy efficiency and demand response.)

DOE's Primary Energy Service Performance Contractors

Ameresco
Chevron Energy Solutions
Clark Realty Builders
Consolidated Edison Solutions
Constellation Energy Projects & Services
FPL Energy Service
Honeywell International
Johnson Controls Government Systems
Lockheed Martin Services
McKinstry Essention
Pepco Energy Services
Siemens Government Services
TAC Energy Solutions
The Benham Companies
Trane U.S.

The GSA handles purchasing and procurement for multiple federal agencies, and many federal contractors hold what are known as multiple award schedule contracts that GSA administers. "A multiple award contract schedule allows any federal government agency and some state agencies and some contractors to the federal government to access the products and services through the GSA," said Al Tattersall, a senior vice president of federal contractor **GP Physics**. "The advantage to agencies in doing it this way is that it reduces the amount of time for contracting." GSA schedules have already been analyzed and vetted for fair pricing of products and services, and individual agencies can essentially shop among GSA schedule holders for vendors, then work through GSA to execute the contract quickly.

According to Lippert, federal agencies have different preferences regarding whether to procure services through

a GSA schedule or handle their own procurement. "It really gets down to a specific branch of DOD, a region or even a specific base within that region," he said. "The preference may come down to a certain individual procurement officer's experiences."

The eLibrary on GSA.gov can be used to locate firms that hold multiple award schedule contracts. With stimulus money flowing, many of these firms will be already looking at how to ramp up their capabilities through subcontractors. "We have been approached by government agencies with which we have contracts, and we've been told that they are expecting stimulus funding that would expand the scope of work that we would provide through our existing contracts," said Tattersall.

There's also the option to look for specific contract opportunities being offered directly by federal agencies. GSA's FedBizOpps.gov website lists any contract greater than $25,000, according to Tattersall. "In this case, you're not looking for the contract vehicle but the types of procurement that are being opened for solicitation," he said. He suggests prioritizing solicitations based on NAICS codes and geography for regional firms, then contacting the relevant agencies directly.

For businesses that meet federal small business criteria (see SBA.gov/faqs), most federal agencies have liaison staff who can assist in locating prime contractors who may be bidding on specific projects. "You tell them the type of work you do and they will assist you, including telling you companies who are bidding on contracts where you could be a good subcontractor," said Tattersall. "Almost every military facility, including NASA, has someone responsible for getting small businesses involved in acquisition primarily because Congress sets targets for small business contracting."

Tetra Tech's Lippert says that such requirements will lead his firm to subcontract even when it possesses all the needed capabilities for a contract in-house. "We're a large firm and proud of our broad expertise, but since a number of federal clients have small business requirements in their contracting, we'll plan to exceed those," said Lippert. "There could also be niche technologies where we need to bring in a technical specialist."

(Tattersall and Lippert also noted that for small firms willing and able to become qualified as federal contractors, contracting requirements can put their firm in the prime contractor spot with larger firms acting as subcontractors. "Some of the small-business set-asides can be for quite sizeable contracts, so there's often a real need for the expertise and experience that a large business can provide. We are in mentor-protégé and joint-venture relationships with some small businesses that qualify for set-asides," said Lippert.)

As far as making contact with and cultivating a subcontractor relationship with a federal contractor, Tattersall recommends the additional step of registering as an interested party for solicitations of interest on FedBizOpps.gov. "They'll post your name as a company looking to subcontract."

Lippert underscores Tattersall's advice about using the small business liaisons at DOD facilities, but he says old-fashioned networking and marketing can be valuable as well. "Getting involved with groups, where they want to do business, that will give them insight and referrals is a good start." he said. "The Society of American Military Engineers, for example, has monthly meetings and is a great place to do business networking."

"We certainly get cold calls and have people sending us information, but even in this modern world where we're all tied together through technology, my preference would be to meet someone face to face at a SAME meeting or have an introduction facilitated by a small business liaison from one of the DOD branches." If such introductions lead to a potential relationship, it is always preceded by thorough vetting, said Lippert. "Just because we have this glut of funding, we'll still continue to do thorough vetting of subcontractors. The taxpayers don't want to see projects funded that aren't high quality." ☼

Reasons for Regional Variations in U.S. Geothermal Power Prices

- 1) Transmission Access; 2) Utility Attitude towards renewables; 3) RPS requirements; 4) Supply and Demand; and 5) Competition from other sources
- Regulatory structure, energy efficiency mandates, market manipulation of pricing
- RPS states, proximity to fuel, natural resource availablity, transmission constraints, labor costs
- RPS and transmission infrastructure
- States pushing RPS have higher prices; regions with marginal pricing based on natural gas-fired generation currently have lower pricing
- Transmission access, level of Renewable Portfolio Standards, utility attitude towards geothermal
- Transmission capacity/ installed power conversion technology
- Free market pricing is subject to the law of supply and demand, and stimulus/incentive. We are seeing voluntary standards causing some important rises in price paid for renewables, with incentives coming from contribution to portfolio in a utilities footprint, and what that utilty thinks it can safely pass to their rate base. A Federal Renewable Porfolio Standard will change the game significantly (at a cost to all rate payers). Time will tell, but in the meantime, there is sufficient demand and pricing to make hydrothermal projects work financially, and that is what it's all about.

Source: CCBJ 2009 Geothermal Survey conducted in April 2009. Question was: Please comment on variations in power prices in U.S. states and regions and what causes these variations.

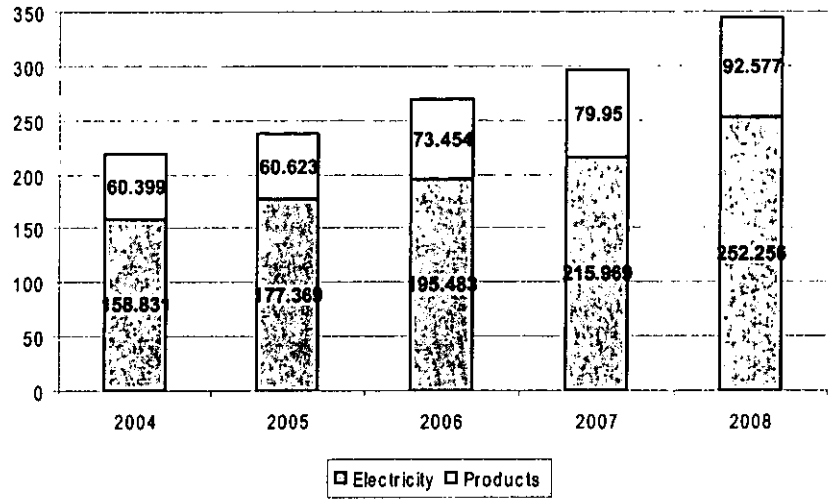
Ormat Leads Market With Technology and Vertical Integration

Ormat is the clear leader with $350 million in sales, but more competition is seen for low-temperature geothermal projects using binary technology

The geothermal power industry is made up of project developers and independent power producers (IPPs); scientific and technical consultants; drilling outfits and drilling technology firms; manufacturers of power plant equipment; and consulting engineers who explore for resources and design and build power plants. Many firms perform multiple roles in this value chain, but there is only one truly vertically integrated corporation whose activities and revenue streams stretch from resource exploration through equipment manufacturing to engineering, procurement and construction (EPC) contracting and power sales: Ormat Technologies.

According to its 2008 annual report, Ormat generated $344.8 million in revenues in 2008, 16.5% growth over 2007. Ormat's power sales revenues from its geothermal plants (both Ormat-built and acquired) and recovered energy generation (REG) plants (see below for more on REG) accounted for $252 million or 73.2% of revenues with product sales accounting for $92.6 million or 26.8% of 2008 revenues. Ormat built 109 MW of company-owned geothermal and REG capacity in 2008 and increased its portfolio to 505 MW. Ormat is on track to build between 82 MW to 94 MW by the end of 2010 for its own portfolio, according to a company spokesperson.

This cash flow from electricity sales puts Ormat in an enviable position relative to smaller developers that are struggling for needed upfront development capital in the current economic climate. "The cash flow generated by our portfolio of operating geothermal and REG power plants provides us with a robust and predictable base for our exploration, development and construction activities, to a certain level without the need to tap into external liquidity sources," notes the annual report. "We believe that this gives us a competitive advantage over certain competitors whose activities are dependent on external credit and financing sources, particularly in light of the current global credit and financial crisis."



Source: Ormat 10-K for fiscal year 2008 ended December 31, 2008. Products includes revenues from four groups: Power Units for Geothermal Power Plants; Power Units for Recovered Energy-Based Power Generation; Remote Power Units and other Generators; and Engineering, Procurement and Construction (EPC) of Power Plants. Electricity includes three groups: Energy and capacity; Lease portion of energy and capacity; and Lease income.

The company's reported highlights for the last year alone show just how broad and diverse its geothermal operations and revenues are. Among its accomplishments: Signing a $65 million contract to supply and oversee construction and startup of a geothermal power plant in Costa Rica; Starting commercial operation of 35 MW of new plant capacity in Kenya; Securing rights to some 150,000 acres of land in Alaska, California, Hawaii, Nevada, Oregon and Utah; Acquiring 51% ownership of a New Zealand geothermal plant; Signing a joint venture to develop a new geothermal project in Nevada; joining a power development consortium in Indonesia; Signing EPC contracts with developers in New Zealand and Nevada worth $42 million and $76 million; Signing a $16 million supply contract for a geothermal project in Turkey; And closing a $63 million tax credit financing deal for an existing plant.

Israeli Roots, But U.S. Was 72% of Ormat's Revenues in 2008

A U.S. company with Israeli roots, Ormat was founded to develop and market heat exchangers and turbines using the organic rankine cycle (ORC) which Ormat founder Lucien Bronicki and his collaborator Harry Zvi Tabor, both Israeli, developed in the early 1960s. ORC uses working fluids with boiling points lower than water to recover energy and generate steam and power from heat sources that would otherwise be insufficient to power steam generators. The original technology was developed at the National Physical Laboratory in Jerusalem in the frame-

Ormat 2008 Revenues ($mil)

	Electricity	Products	Total
Foreign	$45	$51	**$96**
USA	$207	$42	**$249**
Total	**$252**	**$93**	**$345**

Source: Ormat 10-K for 2008.

work of solar energy research. Lucien Bronicki formed Ormat in 1965 in Israel.

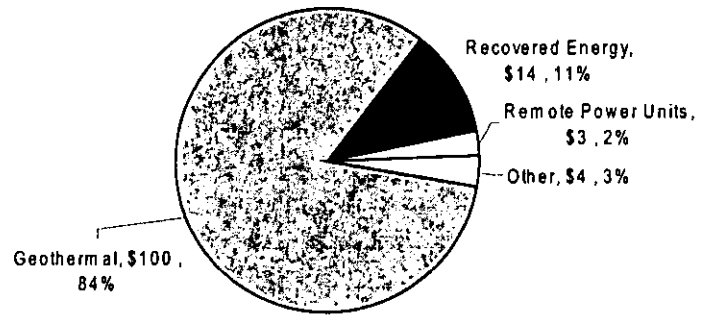
Bronicki originally targeted solar thermal applications in remote off-grid villages, but with that technology facing poor commercial prospects, what emerged from his work was the small Ormat Energy Converter (OEC), a power unit for remote telecom stations, offshore oil and gas rigs and other off-grid facilities that need small amounts of electrical power.

In 1972, Ormat was established in the United States where it supplied OEC units to the Trans Alaska Pipeline. According to material published on Ormat's website, for remote power applications the OEC uses natural gas, kerosene, diesel and other combustion fuels to heat the working fluids, which the hermetically sealed unit condenses and re-uses, allowing continuing operations for many years with periodic refueling and maintenance. More than 3,500 OECs of up to 7 kW capacity have been have been installed in 63 countries, according to Ormat's website.

Ormat turned its attention to geothermal, solar and biomass in the 1970s, with geothermal eventually becoming its major focus. Its business model has steadily evolved from that of a supplier of power systems and components to a vertically integrated firm that builds, owns and operates its own geothermal power plants as an IPP, as well as an EPC contractor that builds power plants for other geothermal project developers.

The company continues to market small OECs and REG systems. For its REG segment, Ormat foresees major growth by selling to North American natural gas pipeline operators who produce waste heat at compression stations driven by gas turbines. Ormat reports that the Federal Energy Regulatory Commission (FERC) is asking proponents of new or expanded pipelines to improve their energy efficiency.

Ormat Product Revenues: Expected Sales in 2009 ($mil)



Source: Ormat 10-K for 2008. Products include revenues from four groups: Power Units for Geothermal Power Plants; Power Units for Recovered Energy-Based Power Generation; Remote Power Units and other Generators; and Engineering, Procurement and Construction (EPC) of Power Plants.

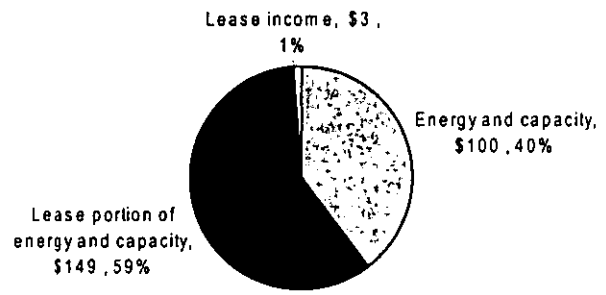
Ormat has begun building 5 to 6 MW REG systems along interstate natural gas pipelines and midstream gas processing facilities. The company also see opportunities for REG in the power sector in Colorado, Massachusetts, Ohio, Pennsylvania, Washington and other states where utilities can install REG systems on power plants and count the capacity toward their renewable energy standards. Additionally, North and South Dakota and the U.S. Department of Agriculture have qualified REG systems for low-interest loans. In North America, Ormat estimates the market potential for REG at 1,000 MW. After building out this domestic market, the company plans to target Europe which has "similar potential," according to the report.

By contrast, the potential for adding geothermal power in the United States is much larger. Ormat's Director for Policy and Business Development Paul Thomsen says the company sees the potential for geothermal power capacity to grow to 30,000 MW to 40,000 MW by 2050, or an order of magnitude larger than the less than 3,000 MW in 2009. As has been widely reported, a 2007 Massachusetts Institute of Technology study projected a potential of 100,000 MW of geothermal generating capacity if enhanced geothermal systems (EGS) can be deployed successfully. (For more on EGS, see page 29.)

More Competition for the Binary Technology Segment

Ormat built its geothermal power business by leveraging its ORC expertise to create what became known as binary geothermal power plant technology. When Ormat first entered the geothermal market in the early 1980s, its technology was an upstart contender.

Ormat Electricity Revenues: 2008 ($mil)



Source: Ormat 10-K for 2008

Most of the action was focused on using conventional flash steam generation with high-temperature geothermal resources of 350 degrees fahrenheit and above. But when Ormat's technology came on the scene, those high-temperature resources were starting to become more scarce because they were the most favorable for geothermal power and therefore developed first. By the mid-1980s, geothermal project developers increasingly needed energy conversion technology that could make use of lower-temperature resources. "Until then people had only been looking for resources that had high temperature steam," said Thomsen.

While Ormat grew its business over the next two decades, it also facilitated the growth of the geothermal industry. Its niche technology position grew into a commanding lead in the fast-growing binary power plant segment, leaving the steam segment to other players, mostly large turbine manufacturers. "Ormat has never tried to compete with Mitsubishi or GE or other manufacturers on huge steam turbines," said Thomsen.

One industry veteran estimated that binary technology accounts for about 10% of the existing stock of geothermal capacity worldwide, and that Ormat has built 95% of those plants. Despite its lower penetration in commissioned power plants, binary technology represents the greatest growth potential because of the prevalence of undeveloped geothermal resources under 350° F, according to many industry experts. (Other factors go into the choice between flash steam technology and binary technology; see Nevada Geothermal profile on page 27 for more information.)

"In the United States, the low-temperature resources are huge," said Enrique Lima, general manager for overseas business of **West Japan Engineering Co.** (West JEC), a prominent and globally active geothermal consulting engineering firm. "The amount of hot water available is very large and the temperatures are well suited to the application of binary power generation. This is why many companies are trying to tap these resources."

Lima points to other countries where binary geothermal development could be the pivotal enabling technology for geothermal because of the abundance of underground reservoirs of 350° F or lower. "Exploration and development of low-temperature resources is happening in countries as diverse as Australia and Greece, and in countries like Hungary, Romania, and Jordan, where oil and gas exploration has led to discoveries of hot water and interest in geothermal energy."

According to Tim Stephure, clean and renewable power generation analyst at **Emerging Energy Research**, binary technology is slightly more expensive than conventional flash steam generation technology, but Stephure says this disadvantage is mitigated by the fact that the exploration and drilling risks are reduced because developers have a better chance of tapping resources of sufficient enthalpy

Ormat Projects

Domestic	Location	MW*	Power Purchaser	Contracts Expiration
Ormesa Complex	East Mesa, CA	57	Southern California Edison Co. (SCE)	2018
Heber Complex	Heber, California	92	SCE / SoCal Power Public Authoriy	2015-2031
Steamboat Complex	Steamboat, Nevada	84	NV Energy, Inc.	2018-2028
Mammoth Complex**	Mammoth Lakes, CA	14.5	SCE	2014/2020
Puna	Puna, Hawaii	30	Hawaii Electric Light	2027
Brady Complex	Churchill County, NV	22	NV Energy, Inc.	2022/2027
North Brawely	Imperial County, CA	50	SCE	2029
OREG 1	North and South Dakota	22	Basin Electric Power Cooperative	2031
OREG 2	North Dakota	5.5	Basin EP Coop	2033
Total Domestic Operating Projects		**377**		
Foreign				
Momotombo	Nicaragua	28	DISNORTE/DISSUR	2014
Zunil	Guatemala	24	Instituto Nacional de Electricidad (INE)	2019
Olkaria III Complex(8)	Kenya	48	Kenya Power and Lighting Co. Ltd.	2029
Amatitlan	Guatemala	20	INE	2026
GDL	New Zealand	8	Norske Skog Tasman	2015
Total Foreign Operating Projects		**128**		
Total Operating Projects		**505**		Expiration+
Under Construction				
OREG II	ND, MN, MT	16.5	Basin EP Coop	25 years
Peetz	Denver, Colorado	4	Highline Electric Asn	20 years
Puna	Puna, Hawaii	8	Hawaii Electric Light Company (3)	n/a
GRE(4)	Minnesota	5.3	Great River Energy	20 years
East Brawley	Imperial County, California	30	Southern Calif. Power Public Authority (5)	n/a
Jersey Valley	Nevada	18-30	NV Energy, Inc.	20 years
Total Under Construction		**82-94**		

*Source: Ormat 10-K for 2008. Projects under ownership only; *Ormat Share in Generating Capacity MW; **50% ownership; +Expiration in years following commercial operation date*

(heat energy) for the binary process. "In cost comparisons to wind or varying solar technologies, binary geothermal technology is very economically favorable," said Stephure. "The low-temperature market will probably have the highest growth rate going forward as there are so many more areas that can be explored.... Nevada has tremendous opportunities in this regard as well as some other states like Utah."

Ormat's Thomsen underscored Stephure's viewpoint about the lower risk levels and costs of drilling for low-temperature geothermal reservoirs. "Probably 90 percent of the geothermal projects in existence today were built on top of reservoirs that had some kind of surface expression such as hot springs or rapidly melting snow," he said. "Now that most of these have been developed, the industry is looking for what we call blind resources."

"Geothermal is where the oil & gas industry was in the 20s and 30s when they thought they were running out of oil because most of the reservoirs with surface manifestations had been utilized," said Thomsen. "We're now looking at deeper more moderate temperature resources that aren't inherently obvious or haven't been developed previously. In this phase, the advantage of Ormat's technology being able to user lower temperature heat is critical."

Stephure noted that European countries are banking on using binary technology as well as emerging EGS technology to tap the lower temperature geothermal resources under their soil as well as hot dry rock (HDR) resources. "A lot of European countries don't have those high-temperature resources you see along the Pacific Ring of Fire," said Stephure. "Germany has implemented a feed-in tariff for geothermal of up to €0.27. The base is €0.20 with enhancements of €0.04 if you do combined heat and power and €0.03 if you do EGS. This is the first direct incentive of this kind." ☼

Technology Providers and Developers Vie to Compete With Ormat in Emerging Geothermal Niches

United Technologies, Raser, Turbine Air Systems, Exorka and others develop in manufacturing, the lab and in the field.

Although Ormat dominates the low-temperature binary segment of the geothermal power market today, competitors have emerged in the last several years. **United Technologies Corp.** is its most high-profile competitor on the power systems technology front. Since 2006, UTC has marketed its PureCycle binary technology systems for geothermal power. PureCycle is a 280-kW modular unit that can be deployed in arrays to create commercial-scale plants. According to Michael Ronzello, North American sales and business development manager for **PureCycle** (marketed by UTC's **Pratt & Whitney Power Systems** division), PureCycle promises faster construction cycles. "Our modular approach to power plant deployment drastically reduces construction time," said Ronzello, indicating that plants can be constructed in 6-12 months (after hot water supply is established). "We have the capability to leverage Pratt & Whitney Power Systems 20 plus years of expertise and experience in the power business to provide full turnkey geothermal power plants using PureCycle".

While UTC doesn't publicly disclose prices for its equipment, Ronzello said the company expects to compete with Ormat's cost per MW of capacity by sourcing components from a UTC-owned affiliate. "We use off-the-shelf components and technology from our sister division, Carrier, the leader in commercial HVAC equipment," he said. According to Ronzello, Carrier produces components for PureCycle "in a pre-engineered, pre-manufactured fashion that drives down costs, increases quality and allows customers to take advantage of the lead time that is common in Carrier."

Raser Gains Efficiency With Networking

UTC's largest customer and best advocate is **Raser Technologies** (Provo, Utah). Raser has leveraged its expertise in electric motor technology to develop methods of networking the modular UTC units for optimal performance and efficiency. "Just like there are people who make computers and people who network computers together to function better, we've figured out how to network [the UTC PureCycle units] together so they can work in harmony and produce electricity more efficiently," said Richard Putnam, Raser's director of investor relations.

It's not clear yet how UTC's PureCycle systems will compare with Ormat's in terms of performance, costs and reliability. The geothermal developer community, while not unhappy with Ormat's equipment and EPC work, would certainly welcome additional competition in binary technology. But with over 20 years of experience and a proven ability to execute the guaranteed EPC contracts that lenders need to see before financing projects, Ormat will not be an easy competitor to take market share from. "We have been able to simplify our processes over time," said Thomsen. "We have fewer moving parts. We have a low speed turbine that doesn't require a gear box. Our power plants have become much more efficient over time [and EPC] projects much more streamlined and more efficient [resulting in] longer run times, greater longevity, less wear and tear on turbines, less opportunity for pump failure, less piping."

The industry is watching closely to see how the first Raser-UTC plants perform and what their construction costs are. Raser brought its first project online in 2008, the 11-MW Thermo No. 1 plant in Beaver County, Utah. According to Putnam, production wells drilled for the

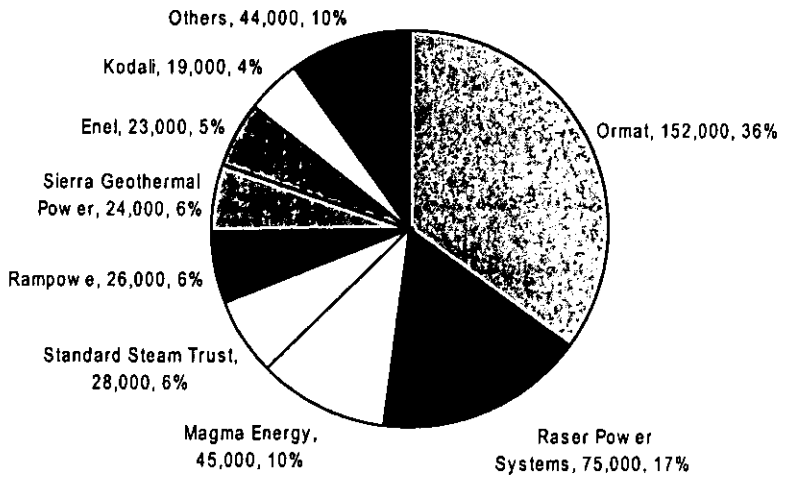
plant revealed a larger-than-expected geothermal reservoir capable of supplying steam for more than 200 MW of power plant capacity. "We had thought there were maybe 20 to 30 megawatts, but after doing some nice drill-out, GeothermEx, an independent geothermal consulting company, was able to verify and independently report that this is now a 230 megawatt resource," he said.

Raser's annual report for 2008 reported a capital cost for Thermo No. 1 of $88.1 million, with at least another $9.5 million needed to get the plant up to full operating capacity. That would seem to indicate a capital cost of about $7,000 per kilowatt of gross capacity. (After supplying its own pump loads Thermo No. 1 will produce 10 to 11 MW net from gross power capacity of 14 MW). That amount is far higher than the typical $4,000 per kW of gross capacity cited by developers at the recent Geothermal Innovation and Investment Conference or the $3,500 to $4,500 per kW range cited for Ormat plants by Ormat's Thomsen. (Those cost ranges include the highly variable cost of resource exploration and wellfield development. "We know the price of plants we build down to the penny. What we don't know is the cost of developing the resource," said Thomsen.)

But according to Putnam and Raser CEO Brent Cook, the nearly $100 million price tag for Thermo No. 1 included the production wells that revealed the reservoir's very large potential plus the cost of a larger transmission line to ship more electrons than anticipated to the company's electricity customers (currently the City of Anaheim, Calif.). "We are comfortable that the $57 to $59 million range is accurate for non–recurring development costs," wrote Cook in an email. "We expect our costs to be $3,800 to $4,200 per MW installed cost."

Raser's Beaver County development is just the opening salvo in a four-state development program that the company expects to yield hundreds of megawatts. Indeed, Raser aims to become a major developer and IPP operator of geothermal projects in the United States, Indonesia and elsewhere.

BLM Geothermal Competitive Leases by Acres, 2007–present



Source: Compiled by Emerging Energy Research; By state the 2007-2008 leases are 52% in Nevada, 34% in Utah and 9% in Oregon, 4% in Idaho. Others include Agua Caliente, Oski Energy, Geothermal Technical Partners, Silver State Geothermal, Vulcan Power, Geothermal Rail Ind. Dev., Miller Dusty, S4 Consultants, Montera Energy Ventures, US Geothermal, Calpine, First Covenant Construction, US Renewables Group, Kelsey South, High Valley. Figures in acres rounded to the nearest thousand acres. BLM is Bureau of Land Management.

After Ormat, Raser is the second largest acquirer of geothermal leases on federal land since 2007. According to figures compiled by **Emerging Energy Research**, Ormat purchased leases to about 150,000 acres (the company owns leases on a total of 220,000 acres according to its annual report), followed by Raser with approximately 75,000 acres and **Magma Energy** with about 45,000 acres (see chart above). "We have accumulated domestic geothermal interests in Nevada, New Mexico, Oregon and Utah," notes Raser's report. "With the help of internal and external geologists, we intend to continue to identify, evaluate and acquire additional interests in properties." And last year, Raser and **Indonesia Power** were the successful bidders on a geothermal concession in Indonesia that covers approximately 100,000 acres with potential resources. At CCBJ's deadline, Raser and Indonesia Power will still finalizing their joint venture agreement.

Turbine Air Systems Exploits Rankine Cycle

Another emerging potential Ormat competitor that some in the geothermal industry are excited about is **Turbine Air Systems** (TAS; Houston), an industrial cooling and heating systems manufacturer that has begun developing technology for geothermal applications. TAS already has a foothold in the power industry with its modular inlet chilling units that can increase the efficiency of gas-fired power plants in hot climates. "TAS has translated this modular construction to geothermal power and advanced waste heat recovery organic Rankine cycle systems," states a company brochure. The company aims to leverage its experience in the power sector to offer design and engineering services for geothermal developers rather than just off-the-shelf sales.

Halley Dickey, director of geothermal business development for TAS, told CCBJ that the company has developed a renewable energy division aiming to provide power plants to solar thermal power projects as well as geothermal and industrial heat recovery. "We've been working on the development of our organic Rankine cycle program for seven years," he said.

"We own some unique patents related to geothermal binary technology." The first plant to deploy a TAS system may be on the horizon, as Dickey said the company is negotiating with an undisclosed potential U.S. client to supply a 15-MW plant in 2010.

Kalina Has Backers & Detractors, Needs Manufacturer

A third competitor in the binary geothermal power systems segment is **Exorka** (Munich, Germany), which markets binary technology based on the Kalina system using an ammonia-water mixture as a working fluid. One speaker at the March 2009 geothermal industry conference disparaged the Kalina system from the lectern, saying that after promising to revolutionize the industry and unseat Ormat, the technology had gotten nowhere. The speaker claimed that there are only two Kalina plants worldwide and neither are operating. One conference participant speculated to CCBJ that the difficulties facing the Kalina process stemmed from its use of a mixture of ammonia and water; because the two fluids boiled at different temperatures, Kalina systems had to cope with constantly changing compositions.

But Exorka's CTO Gestur Bardarson reported that four of five Kalina cycle plants built since the late 1990s "have mostly shown high reliability, although some equipment problems have been present [but] no more ... than can be expected for new technology employed in the first commercial plants." A 2-MW plant in Husavik, Iceland, achieved a capacity factor of between 89% and 96% from 2005 to 2007, according to Bardarson. A 3.3 MW waste heat plant at a **Sumitomo Metal Industries** steel plant in Japan has been running smoothly since 1999 with an annual capacity factor as high as 99%, he said.

Raser's Richard Putnam told CCBJ that company staff has evaluated Kalina technology and visited some of the pilot plants. "We believe the technology has a positive operating history that should be discussed. It is unclear who will take the manufacturing lead on the technology, but we believe the technology is sound and proven."

There is also a prospective nano-technology entrant, Power Chips being developed by Gibraltar-based **Borealis Exploration**. The technology was announced in 2003 with a promise of superior power conversion for geothermal applications, waste heat recovery and other applications. A news release described Power Chips as "solid state thermotunnelling devices which use a combination of thermionic emission and quantum mechanical electron tunnelling to increase the rate of electron emission in solid-state converters." But Power Chips appears to either be in deep stealth mode or inactive since the last news relase posted on its website is more than two years old. (An email inquiry to Borealis was not returned by CCBJ deadline.)

Ormat, of course, is not standing still technologically. Thomsen says that the company's more than 25 years of experience designing, managing and operating geothermal plants gives it a technical edge over prospective competitors. "Converting heat to electricity is very expensive and hard to do," said Thomsen. "Some of our competitors have tried to do cookie-cutter type plants that they can produce rapidly. We started with small units and gradually built larger and larger units, refining our knowledge and expertise continually."

Ormat also has an operational edge that enables it to get the most MWh out of its plants for the lowest operating costs, according to Thomsen and Ormat's annual report. "Our intimate knowledge of the equipment that we use in our operations allows us to operate and maintain our projects efficiently and to respond to operational issues in a timely and cost-efficient manner," states the report. "Moreover, given the efficient communications among our subsidiary that designs and manufactures the products we use in our operations and our subsidiaries that own and operate our projects, we are able to quickly and cost effectively identify and repair mechanical issues and to have technical assistance and replacement parts available to us as and when needed."

Ormat Takes a Crack at EGS

Ormat is pushing the frontiers of geothermal technology in two key initiatives with the **U.S. Department of Energy**, one to explore the potential to exploit hot water that is co-produced with oil and gas and another to advance enhanced geothermal systems (EGS).

At the **Rocky Mountain Oilfield Testing Center** (RMOTC) in Wyoming, a 250-kW Ormat binary power unit started generating electricity in September 2008 using heat from 190° F water that is co-produced with oil. The potential to generate on-site power from such a set-up is enormous. RMOTC estimates that U.S. oil and gas wells that produce hot water along with hydrocarbons could generate "upwards of 5,000 MW of power," according to an RMOTC news release.

Ormat's Thomsen told CCBJ that the project is "over-producing what we had expected it to do." But moving ahead with co-production at oil and gas drilling sites will be a challenging endeavor. For one thing, there's the fact that according to RMOTC, the water recovered with oil or gas is usually only heated to a maximum of 220° F, far lower than what geothermal developers prefer to produce power economically. Furthermore the costs of operating such a system will depend on how the hot water is disposed of, i.e., through reinjection or surface dumping.

Probably much more significant to the future of geothermal power is Ormat's DOE-funded work on EGS with collaborators **GeothermEx**, **University of Utah**, **U.S. Geological Survey** and others on two

EGS demonstration projects.

As discussed in in the following feature on enhanced geothermal systems, EGS has the potential to vastly expand geothermal if it allows power to be produced successfully from hot dry rocks—as opposed to the conventional hydrothermal resources relied on for all geothermal power today, both flash and binary. The demonstration projects aim to hydraulically stimulate fractures that can enhance the production of hot water of sufficient enthalpy to generate additional power. "It's still very early stage R&D, but we're excited about not only developing technology to create standalone resources for EGS but also to create new life or viability for existing resources."

"We still need to prove the technical viability, and then get to the point of proving commercial viability," said Thomsen. "Ormat's experience has shown us that you can have complete technical success and zero commercial viability and vice versa." He also averred that it will be important to focus not just on the potential of EGS to greatly expand the pool of resources available for geothermal power but to look for ways to use the emerging technology to enhance existing geothermal power sites.

"If you can go back to wells that are less productive and, for lack of a more scientific term, tinker with them and produce more heat, we might determine that our potential hydrothermal resources may be much larger than we thought. For example, if you drill a well in a standard hydrothermal resource and don't get adequate permeability or heat, you might be able to use EGS technology to fragment back into the reservoir and stimulate adequate permeability and heat."

Growing Organically

With its healthy balance sheet and dominant vertically integrated position, Ormat might be expected to be on the hunt for project developers long on leases but short on capital. But according to Thomsen, the firm is reticent to diminish its third-party customer base through acquisition even though that might provide competitive advantages. "The only time we compete directly against another developer is when we're bidding on a resource at the federal land auctions," said Thomsen. "Once another developer is successful in achieving its resource position, we look to provide them with third-party power plant equipment."

Thomsen says that last year Ormat executives were asked by some in the geothermal industry whether they were considering making a bid for **Nevada Geothermal Power** when the developer was trying desperately to finance its Blue Mountain Project during the 2008 economic collapse. "People asked us 'Are you looking at this as potential acquisition?' We said no. We don't want potential third-party clients living in fear that we would acquire them when they run into financial difficulties."

Some financial analysts or deal-makers might argue Ormat is undervaluing the benefits of consolidation. But it's hard to argue with a business model in which Ormat's development arm pushes ahead with its own projects while earning revenues from equipment sales and EPC contracts—including $76 million from Nevada Geothermal for designing and building the Blue Mountain project.

Ormat's future is clearly tied to supplying and servicing a vigorous and growing geothermal industry, and to that end the company is a cheerleader for its counterparts as well as a competitor. Thomsen echoes a theme heard commonly in geothermal circles: The industry deserves more respect and recognition, and when elected officials, utility commissioners and activists talk about the importance of renewable energy, geothermal should be mentioned in the same breath as wind and solar.

"On one hand it can be frustrating that people don't recognize geothermal and its reliable baseload attributes as compared to wind and solar," said Thomsen. "But on the other hand, the investor-owned utilities we sell power to all know who we are and what we do. Geothermal might not be on the front page of the Wall Street Journal or the New York Times, but there are not many utilities who aren't familiar with geothermal. Serendipitously, after CCBJ interviewed Thomsen in April, Morgan Stanley put geothermal power on the cover of the *Wall Street Journal* on May 20, 2009, with a full-color ad touting geothermal as a sound investment, while promoting its expertise on the industry. "Unlike wind or solar energy, geothermal utilizes a constantly present energy source —the Earth. Just below our feet lies an industry that could reach $122 billion by 2030." While Morgan Stanley's 20-year valuation of the industry may be little more than an educated guess, the firm's promotion of its expertise harkens to what Thomsen says utilities have known for years: "To quote Michael Yackira, CEO of **NV Energy**, 'Geothermal projects don't look any different to an IOU than any other fossil fuel project,' While that's not sexy, it's a badge of honor for the industry. We're seen in their integrated resource plans as being just as reliable as coal or natural gas plants." ☼

Typical Geothermal Plant Development Costs ($/kw)

Development Stage	Cost ($/kW)
Exploration and resource assessment	400
Well field drilling and development	1,000
Poewr plant, surface facilities, transmission	2,000
Other dev't costs (fees, working cap, contingency)	600
Total development cost	4,000

Source: Geothermal Tomorrow, U.S.Department of Energy's Office of Energy Efficiency and Renewable Energy; Costs for a typical 20 MW plant or a total of $80 million; Does not include financing charges of interest rates 5-6% for some utilities or as high as 15% for IPPs."

Nevada Geothermal Power, Last in Before the Credit Freeze, Looks to Heat Up the Geothermal Market

Like several other pure-play geothermal developers, Nevada Geothermal Power (NGP) is a Canadian company with a U.S. subsidiary targeting development prospects in the lower 48. NGP became something of a celebrity in the small U.S. geothermal world last year because it secured project financing for its 49.5 MW Blue Mountain power plant near Winnemucca, Nevada, just before credit markets locked up in the third quarter of 2008. But the company's experience also illustrated just how difficult it is to finance a geothermal power project in this economic environment.

The credit facility NGP received from Trust Company of the West on August 29, 2008 enabled it to give Ormat Technologies a full notice to proceed on a previously negotiated $76 million engineering, procurement and construction (EPC) contract and to conclude a $4.5 million deal with Wilson Utility Construction for a transmission line to the regional grid. As of spring 2009, the project was on schedule and NGP expected Blue Mountain to be in commercial operation by the end of the year. The power buyer is investor-owned utility NV Energy.

"Our timing was perfect," said CEO Brian Fairbank in recounting his firm's dash for cash last summer. "We had been working with Morgan Stanley on a 30-month construction loan that would have then been replaced with production tax credits for permanent financing." With a proven resource of 50 MW (40 MWe) and the guaranteed turnkey EPC bid from Ormat, the project looked solid, until the credit markets started to unravel in mid-2008. "All summer we'd been sitting down with Morgan Stanley and the syndicating banks trying to close the deal, but it was apparent even then that the credit markets were not working. Around the end of July we were basically running out of time and needed to move forward." That's when NGP got its financing deal done with TCW—at 14 percent.

Cost of Developing a Geothermal Project

High front end costs

- High upfront confirmation costs, compared to other renewables
- Drilling, money, leasing, time

Phasing exploration mitigates risk

- Geochemistry, geology, geophysics and permitting: $2.5 million
- Temperature gradient drilling, slim-holes: $2.5 million
- Production test wells: $3.0 -$6.0 Million X 2
- $15 million plus to feasibility! Requires high risk upfront equity!

Source: Nevada Geothermal Power, presentation by CEO Brian Fairbank at Greenpower Conferences' March 2009 Geothermal Innovation and Investment conference

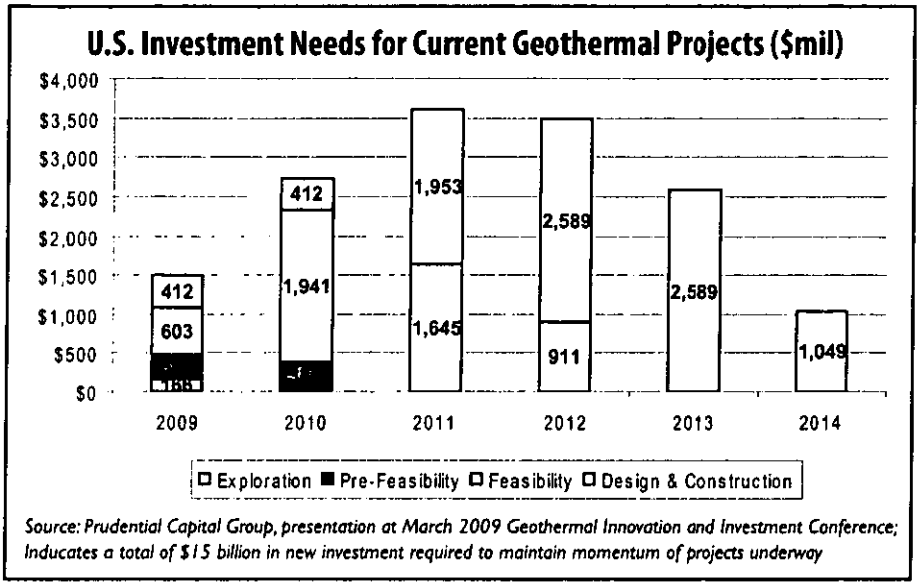
"In today's economic environment, this financing looks good," said Fairbank. "It's a facility up to $180 million that we draw as we need it." Fairbank says NGP is currently packaging a production tax credit (PTC) based financing, a task that is by no means easy since the tax credit capacity of U.S. financial institutions has shrunk dramatically with their declining profits. The American Recovery and Investment Act (ARRA) stimulus bill extended the "placed in service" date for tax credit qualification for geothermal projects to December 31, 2013, so Fairbank is confident that buyers will be found. The plant's commercial operation date (COD) looming—it could arrive by October 2009—and the impetus to take out the 14% debt is rather compelling.

Selling the PTCs is NGP's most preferable option; as noted in CCBJ's Q1 2009 edition, the House-Senate Joint Committee on Taxation estimates that PTCs taken over the 10-year qualification period are worth roughly 50 percent more than the investment tax credit that Blue Mountain and other renewable generators can also qualify thanks to ARRA. "The PTCs are worth $21 a megawatt-hour to start with, indexed to inflation. So if we're selling power at $75 to $80 per megawatt-hour, that's pretty significant," said Fairbank. Accelerated depreciation is also on offer, and combined with PTC value, Fairbank figures that NGP can offer a buyer about $100 million worth of tax benefits.

However, in today's climate, Fairbank acknowledges that he may have to go with the new tax credit option provided by the ARRA: a grant in lieu of a 30% investment tax credit (ITC). But like other geothermal developers eyeing the grant-in-lieu-of ITC, Fairbank is concerned about how much of the upfront exploration and drilling costs will be considered tangible costs by the U.S. Treasury for the purpose of calculating the ITC. At CCBJ's deadline, guidance on that issue had not come forth.

As is the case for many geothermal projects, in the process of drilling wells to tap the underground hot water resources at Blue Mountain, NGP ended up hitting one dry-hole—not literally dry but of sub-commercial enthalpy (heat energy)—and some "false starts" in Fairbank's words on injection wells (used to stimulate continuing flow of hot water). "We drilled a well to the north that didn't turn out."

At $3 million to $6 million per well, the ability to include unproductive wells in the investment cost basis that qualifies



Source: Prudential Capital Group, presentation at March 2009 Geothermal Innovation and Investment Conference; Inducates a total of $15 billion in new investment required to maintain momentum of projects underway

for the ITC is not trivial. According to Fairbank and other geothermal developers, typically 20% to 30% of the wells drilled on such a project end up not functioning as expected—but such dry-holes are an inevitable part of development, and they help the developer and its technical consultants understand more about their reservoir and target future drilling more accurately.

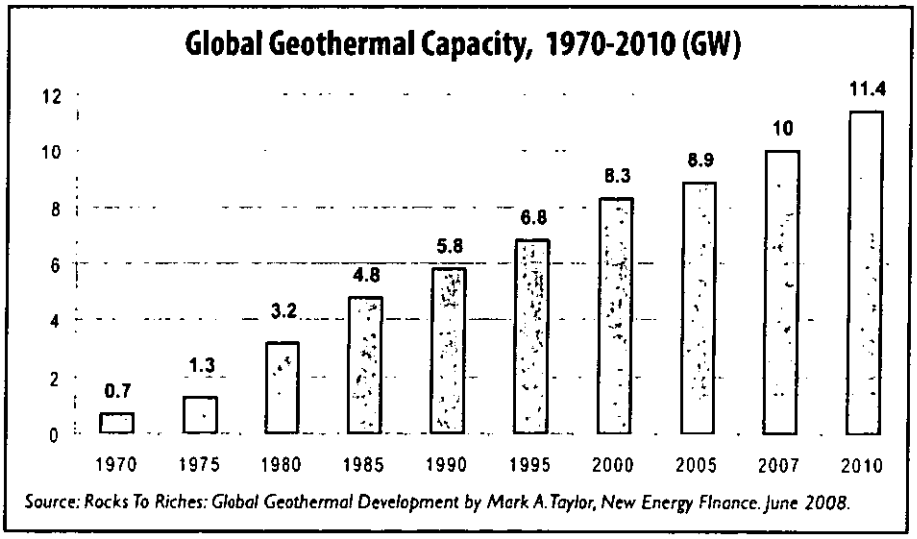
In fact, with the production drilling already completed, this gives Fairbank and his team reason to think that there is another 50 MW of geothermal power capacity to be tapped from the geothermal reservoir under their ground. "In oil and gas terms, there's an inferred or possible resource toward the mountain to the east," said Fairbank. Geoscientific and geochemical indications give strong hints of this. "The water we're producing now is 375 degrees Fahrenheit, but the chemistry of the water indicates that ultimate source temperatures greater than 400 Fahrenheit. In the long run we may not have found the hottest part of the resource." But more drilling is needed to prove it.

And speaking of temperatures, NGP's 375 degree Fahrenheit geothermal resource was hot enough to allow use of conventional flash steam technology—which would have resulted in a somewhat less costly power plant. But early on NGP chose the binary technology offered by Ormat, which uses working fluids and heat exchangers to capture the heat energy in lower temperature geothermal resources. According to Fairbank, the decision was based in part on the fact that while initial drilling turned up 375 degree Fahrenheit hot water, NGP couldn't be sure subsequent wells wouldn't be too cool for flash technology.

Plus, the closed-loop binary systems offered benefits for reservoir longevity and air quality permitting. "With binary you reinject 100% of the water and that helps maintain the overall resource's longevity because you're pressuring the reservoir," said Fairbank. "With flash, you're losing the vapor, about 30 percent of the water."

"Flash plants also have some slight air emissions in the vapor," said Fairbank. The most common is hydrogen disulfide—the rotten egg smell. "[To meet air quality regulations] you have to scrub that out. You can deal with it, but binary is absolutely emission free."

NGP is pursuing development of three other projects: Pumpernickel Valley and Black Warrior in Nevada and Crump Geyser in Oregon. With TCW funding for Blue Mountain only, NGP expects to be in the market for more financing soon. Because the expensive drilling programs must be funded by scarce equity—in the "hyperliquidity" era that ended last year, some debt funding might have been available—NGP is hoping that the U.S. Department of Energy (DOE) decides to use some of its $400 million in ARRA funding for geothermal to subsidize drilling programs. Either that or a piece of the $6 billion in new loan guarantee funds in the ARRA, hopefully made available in a process more streamlined that past DOE loan guarantees. "The existing established loan guarantee program is for technology [but for applicants] it has been more trouble than it was worth," said Fairbank. "My understanding is that the new program may be for other things, including geothermal drilling. The geothermal industry needs that." ☼



Source: Rocks To Riches: Global Geothermal Development by Mark A.Taylor, New Energy FInance. June 2008.

EGS Could Vastly Expand Geothermal Power But Funding of RD&D Projects Needed

Conventional geothermal industry competes with EGS for scarce funding.

In our page one overview for this edition, CCBJ characterized the geothermal power industry as the veteran journeyman shortstop on the baseball team of the Low-Carbon and Renewable Power Segment. Well, if one thinks of the geothermal power industry as a professional baseball team, **enhanced geothermal systems (EGS)** would be the 15-year-old phenom impressing the pro scouts. Only that metaphor is not grand enough. Imagine that the scouts have discovered a whole high school full of future all-stars who are destined to break every baseball record without using steroids and triple the size of Major League Baseball's fan base and revenues. That's just the kind of game-changing status that EGS is gaining in geothermal research and investment circles.

While the U.S. resources for conventional geothermal power—also known as "hydrothermal" because underground hot water provides the steam supply for power plants—are limited to the West and capable of growing to between 30,000 and 40,000 MW, geothermal plants using EGS could be built almost anywhere. A **Massachusetts Institute of Technology (MIT)** study projects that EGS technology could enable geothermal power to supply 100,000 MW of capacity in the United States, nearly 10% of current installed electrical generating capacity.

But as of 2009, EGS (which also stands for engineered geothermal systems and is alternately known as HDR, for hot dry rock) is more like a kid trying out for little league. After three decades of research and field testing, there are no EGS power plants pumping electrons to a utility grid. "So far there have only been test power plants run on true EGS experiments where they've actually fractured the rock and circulated the water," said EGS expert David Blackwell, co-author of the MIT report and a professor of geophysics at **Southern Methodist University** at the March 2009 Geothermal Innovation and Investment conference in San Francisco.

Blackwell acknowledged that European EGS projects in France and Germany are generating grid power, albeit in amounts of 3 MW or smaller. But he told the audience that those projects are not what he considers true EGS because their developers drilled into subterranean rock with existing fractures. "They didn't actually make the fractures," said Blackwell. In Blackwell's and many others view, the first company to accomplish a true EGS project will likely be **Geodynamics** of Australia, which looks ready to culminate six years of R&D with a 1-MW geothermal plant in South Australia's Cooper Basin. The pilot project will power the remote town of Innamincka as early as the summer of 2009, displacing a diesel generator that costs $15,000 a month to fuel. "That will be the first real long-term, large-scale test of EGS," said Blackwell.

EGS Basics

So what is EGS? In a nutshell, it is using hydraulic fracturing techniques—commonly deployed in the oil & gas industry—to open up sealed fractures in hot rocks far underground, then using injection wells to push cold water through the newly opened fractures where it is heated and returned to the surface to supply heat for power generation. EGS "emulates naturally occurring hydrothermal circulation systems—those now producing electricity and heat," wrote Jefferson Tester and co-authors of MIT's 2006 report, *The Future of Geothermal Energy*.

MIT's report has generated buzz in the media and in investment circles. Before the recession, EGS drew some venture capital, which had been rare to non-existing in the mature geothermal industry. **AltaRock Energy**, which aims to develop a pilot EGS project by drilling into granite below the hydrothermal reservoir that fuels The Geysers power plant in California, received $26.25 million from **KPCB, Khosla Ventures, Google.org** and **Vulcan Capital; Potter Drilling** has received $4 million from Google.org.

Not exactly big numbers in the clean energy field where solar took in 40%, biofuels 11% and wind 6% of $8.3 billion in global cleantech investing in 2008. Indeed, most money going into EGS has come from governments, including the United States, Germany and Australia. MIT's report authors warn that governments will have to keep putting up money for some time to come. "It is likely that government will have to fully support EGS fieldwork and supporting R&D. Later, as field sites are established and proven, the private sector will assume a greater role in co-funding projects—especially with government incentives accelerating the transition to independently financed EGS projects in the private sector."

Australia, which has little in the way of conventional hydrothermal resources, is one of the most aggressive EGS funders. The government has pledged about $45 million for pilot projects, and several hundred million dollars in shareholder investments have flowed into about 10 public companies. Along with Geodynamics, the leading firms include **Panax Geothermal** and **Petratherm**. Yet, in the United States, many in the geothermal industry would prefer that government keep the fledgling EGS phenom on a diet and feed them instead, or as the case may be, keep them alive through this current period of capital scarcity. "It's great to spend money on EGS. That's the future," said Doug Glaspey, CEO of **U.S. Geothermal**. "But if you want megawatts on the ground today, you have to capitalize exploration. The way you do that is put it into drilling programs."

Hot Dry Rock vs. Hot Wet Rock

To one pioneering EGS/HDR researcher, starving RD&D to support the existing geothermal industry would be a case of history repeating itself. Donald Brown was one of the three scientists from the U.S. DOE's **Los Alamos National Laboratory** who pioneered HDR and created a test project—one of the few "true EGS experiments" in Blackwell's rankings—at Fenton Hill, New Mexico. "HDR was actually Bob Potter's invention," Brown told CCBJ. "Mort Smith and I modified it, and I wrote the patent."

The Fenton Hill team developed two confined HDR reservoirs, the first from 1975 to 1977 and the second from 1983 to 1985. The first phase was centered at a depth of about 9,200 feet with a mean temperature of 385° F and the second phase was 11,500 feet underground with a mean temperature of 455° F. Contractors **Dowell Oil Well Services** and **Halliburton** fractured the rock with hydraulic pressure until fissures and cracks that had been long sealed by precipitation were forced open—a common technique in the oil & gas industry. This part of the process included a feat that still impresses Brown today: a massive hydraulic fracturing in which Dowell injected 5.7 millions over two and half days at a surface pressure of 7,000 PSI. "No EGS stimulation has ever approached those numbers."

Hoop stress created by the pressurization made the reservoirs tight at their margins. Injection wells pumped cool water down and through the fractures, where it was heated, then up to the surface—so the system operated in a closed loop, comparable to an automobile cooling system. "The stimulated joints were held open by reservoir pressure, a pressure greater than the joint closure stress so that the HDR reservoir was highly dilated," said Brown. "We were not at all worried about the joints plugging up again with dissolved minerals, since all the dissolved mineral species reached equilibrium in the pressurized close-loop circulating fluid within about two weeks. No precipitation occurred thereafter anywhere in the earth loop."

Years of testing concluded in 1995 showed the potential to generate about 1-MW of electric power, so the team began soliciting a partner from the geothermal industry. "It would have involved bringing in a company like Ormat to build a binary power plant," said Brown. "We got bids, the bids were evaluated and a winning contractor had been selected." The project would have provided invaluable information on "how to best produce heat in an engineered HDR reservoir," according to Brown.

"Our modeling suggested that the one-third cubic kilometer reservoir would last 10 to 20 years. It could be extended laterally or in depth, and I've got other tricks up my sleeve to increase the productivity and lifetime, but we would need to run a reservoir to demonstrate those." But Brown says DOE declined to fund the project at the last minute, instead directing money to building a 29-mile pipeline to carry recharge water to The Geysers, then owned by **Unocal, Calpine** and **Northern California Power Authority**. According to a report by some consulting engineers for the project, the $48 million project was 40% funded by DOE and other public agencies.

"It was frustrating," recalls Brown. With a change in leadership at DOE's geothermal program, he says the agency "didn't understand HDR. They didn't understand what we had done. They just wanted to get us as a thorn out from under their saddle. We kept saying how good HDR was and they kept saying 'but the industry doesn't like it so we're not going to fund it.'"

Echoing Blackwell's viewpoint, Brown contends that most existing EGS test programs are not true HDR, but rather HWR, or hot wet rock. Other industry sources and the MIT report confirm this, but note that the aim of these projects is to engineer those currently unproductive hot rocks to increase their permeability and make them productive for geothermal power. Brown contends HWR technology misses the true home run potential for geothermal, however. "Less than 1% of the geothermal resource is naturally occurring fluids in place, either along faults or in a steam dome like at The Geysers," he said. "The other 99% is HDR. When you can utilize HDR, you go from a few little fly specks on the world map to the rest of the map."

Regardless of disagreements over HDR vs. HWR, Brown agrees with the rest of the EGS crowd in saying that better drilling technology is needed to enable EGS to go forward on a large scale. While conventional hydrothermal drilling doesn't go much below 10,000 feet, candidate resources for EGS power plants start at 10,000 feet deep and can be as much as 30,000 feet below the surface.

The MIT report says both "evolutionary" and "revolutionary" techniques will be needed; in the former category, the report authors look for "more robust drill bits, innovative casing methods, better cementing techniques for high temperatures, improved sensors, and electronics capable of operating at higher temperature in downhole tools"; and in the second category, "new methods of rock penetration [with] lower production costs."

Brown, who has come back from retirement to work on HDR as a guest scientist at Los Alamos, likes the hard-rock polycrystalline diamond compact (PDC) drag bit now being developed by a company called **Novatek International**. "It can improve the drilling rate by a factor of three and will cut our front end costs down considerably so the economics of HDR become more attractive." Brown is also working with some undisclosed venture capital investors who are considering a demonstration project at Fenton Hill.

"The reservoir is still there, and one of the wells is still in decent shape," he said. "If we started today we would probably have power coming off the lines in three years." He says the investors would look to patent some of the technology coming out of the project and build on their first-in-class reputation and expertise to roll out more and larger EGS/HDR projects... They're willing to lose money on the first power generation demonstration. They know that we have to produce power to go to the bankers in order to get funding to step out into other areas and do this HDR."

This theme was echoed by speakers at the March geothermal conference in San Francisco. "We need to cross that first hurdle of getting some demonstration projects going," said Susan Petty, CEO of **AltaRock Energy**. Government funding will be key, according to Petty and others.

"Hydrothermal projects have high upfront capital costs, but EGS has an even higher upfront capital cost with the added difficulty that it's an emerging technology," she said. "We've going to have to rely on funds from the government to help us continue our R&D and to guarantee loans or to provide low-cost capital so we can get our wells through, set up demo sites and run these systems for a while so we can show they work."

Yet, North American conventional geothermal developers—with more 3,000 MW of capacity in the pipeline largely stalled by the recession—say they need DOE money to go forward. "It's very important that these hydrothermal development programs not get stalled," said Brian Fairbank, CEO of **Nevada Geothermal Power**.

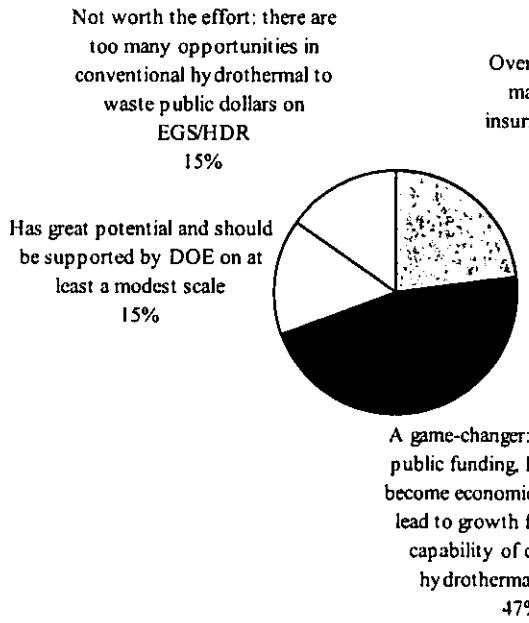
In other words, DOE's $400 million for geothermal is already overcommitted before the agency has had time to come up with disbursement guidelines.

Geothermal industry veterans, lenders and investors expressed a range of opinions to CCBJ about EGS's ultimate viability. "Do I think it can work, sure. But is it economic? I don't know enough to really comment one way or anther," said Ric Abel, managing director for electric finance at **Prudential Capital Group**. "When you start drilling holes 20,000 or 25,000 feet down, and you have to get a fluid down there and back up, you're talking about an enormous parasitic load. I just don't have a good feeling for how the economics will come together."

A veteran geothermal engineer who now consults for investors told CCBJ: "EGS is the holy grail, and like the holy grail it may be just a myth." But many who follow geothermal and other renewable energy technologies contend that with adequate public support, EGS/HDR will fundamentally change the geothermal game. "Work that we are doing in Canada suggests that with adequate investment we can utilize EGS successfully even when temperatures are between 125 and 150 celsius (257 and 302 Fahrenheit)," said Michal Moore, who is a senior fellow at the Institute for Sustainable Energy, Environment and Economy at the **University of Calgary** in Alberta, and a former member of the California Energy Commission. "With the impending changes to coal emission requirements and the retirement of a significant amount of nuclear baseload electric power, the potential of EGS geothermal is critically important."

Brown, who helped invent the concept of HDR geothermal energy, is now finishing a book covering the HDR Project at Fenton Hill and working with his project backers in Washington to get needed support from natural-resource agencies for restarting Fenton Hill (it's located in a national recreation area). At 77, his enthusiasm for EGS is as strong as that of a rookie slugger at the plate. "I want to see HDR out there commercialized and I'm working very hard to do that. Our plant can be online within three years, and from there, the future of HDR is almost unlimited." ☼

Opinions on Enhanced Geothermal Systems (EGS)



Source: CCBJ 2009 Geothermal Survey conducted in April 2009. Question was: Enhanced geothermal systems (EGS), also known as hot dry rock (HDR) technology, can vastly expand the use of geothermal power in the United States and elsewhere. Yet after more than 30 years of research, EGS has only been the subject of small-scale demonstration plants (and many observers say those projects are not using true HDR resources). Please check the category that best describes your general view of the future of EGS/HDR:

Volume 2, No. 4/5 CLIMATE CHANGE BUSINESS JOURNAL® April/May 2009

Let CCBJ Be Your Guide to the Climate Change Industry

A new era of climate change regulation is dawning, accompanied by extraordinary new risks and opportunities for business. Climate Change Business Journal® provides the strategic information that company managers, entrepreneurs and investors need to thrive in this rapidly evolving business environment.

What readers had to say about CCBJ

"A great product that deserves to be widely read."
(Joseph Pallant, Carbon Project Solutions)

"Very comprehensive and obviously the product of a lot of research."
(Jeff Caton, Cameron-Cole LLC)

"Strategically useful information."
(Chai McConnell, ZeroGen, Australia)

CLIMATE CHANGE BUSINESS JOURNAL

IN FUTURE CCBJ NEWSLETTERS

- Energy Efficiency & Demand Response: June/July 2009
- The Clean Energy Infrastructure: August 2009
- Transportation: Vehicles, Fuels & Systems: Sept/Oct 2009
- Solar Energy: November 2009

Prsrt. Std.
U.S. Postage
PAID
Permit No. 2325
San Diego, CA

Mail or fax to Climate Change Business Journal, 4452 Park Blvd. #306, San Diego CA 92116, Fax (619) 295-5743

[ ] Check enclosed [ ] Bill me [ ] Renew my subscription

1 year: Paper Edition $995 1 year: Electronic Subscription $2,500

Name _____ Title _____

Company _____ Phone _____

Address _____

City _____ State _____ Zip _____

Email _____ Fax _____

Satisfaction Guaranteed or Your Money Back!

SAMPLE ISSUE: **Subscribe Today!**
Fax form to 619-295-5743 or visit climatechangebusiness.com

SWAMC
Southwest Alaska Municipal Conference
3300 Arctic Boulevard, Suite 203 Anchorage, AK 99503 p: 907.562.7380 f: 907.562.0438 www.swamc.org

Alaska Peninsula
Aleutian Chain
Bristol Bay
Kodiak Island
Pribilof Islands

February 17, 2010

To Representative Millett:

I am writing on behalf of the Southwest Alaska Municipal Conference in support of HB320 and its goal of making geothermal energy more economically viable in Alaska. Currently in Southwest Alaska there are three geothermal projects being studied in Unalaska, Naknek and Akutan; however, there are plenty of opportunities for further development in this region as much of it is located on the Ring of Fire. By removing the royalty obligation for geothermal resources, this bill would help bring down capital cost impediments and facilitate the implementation of geothermal energy in Southwest Alaska and across the state. This in turn could curb the chronically high energy and heating costs seen in rural Alaska, as well as lay the groundwork for future sustainable energy throughout the state.

For rural Alaskans, there are many reasons this bill must be passed. High energy costs are threatening traditional ways of life in Native Villages and rural communities throughout the state, which are showing signs of decline because fewer career opportunities are available to young people. Implementing environmentally friendly energy with lower, stable costs will provide a chance for Alaska to grow economically while taking advantage of its plentiful renewable resources. Geothermal energy is a proven electrical technology, and removing any unnecessary barriers to its development should only help Alaska reach its renewable energy goals of the future. For this reason, HB 320 not only encourages geothermal development in rural Alaska, it could also provide major benefits to projects along the Railbelt as well.

SWAMC applauds your continued efforts to address the ongoing energy crisis in this state through fiscally responsible measures that promise to create opportunities for growth and sustainability. Please call on me if you have any questions.

Sincerely,

SOUTHWEST ALASKA MUNICIPAL CONFERENCE

Andy Varner
Executive Director

Cc: Representative Johnson
Representative Neuman
Senator McGuire

Alaska Legislature
Representative Charisse Millett

Session:
State Capitol Building, Room 412
Juneau, AK 99801
Phone (907) 465-3879
Fax (907) 465-2069

Interim:
Anchorage LIO
716 W 4th Ave., Room 630
Anchorage, AK 99501
Phone (907) 269-0222
Fax (907) 269-0223

MEMORANDUM

To: House Resources Co-chairs Rep. Craig Johnson, Rep. Mark Neuman

From: Rep. Charisse Millett

Subject: HB 320 scheduling request

Date: Wednesday, February 3, 2010

CC:

I am formally requesting a hearing on House Bill 320 at your earliest possible convenience.

I have included the information in this packet. I am waiting to receive letters of support for the legislation and they will be forwarded to you as soon as possible.

Jeff Turner is the staffer assigned to this legislation. Please have your staff contact him at (907) 465-6588 if you need any additional information.

###