EMERGING RENEWABLE ENERGY TECHNOLOGY MARKETS: CONSIDERATIONS FOR THE ENERGY TRUST OF OREGON

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The state of Oregon adopted a state renewable energy portfolio standard (RPS) in 2007 that represents an ambitious effort to expand the market for clean energy. The intention reflected a desire to bring economic development benefits to the state and to increase the benefits of renewable energy for the state's ratepayers. The RPS targets promise continued strong markets for large-scale wind energy projects. However, the legislation recognized the need to strengthen the state's support of smaller renewable energy projects—namely, by directing the Energy Trust of Oregon (ETO) to address the above market costs of projects that are 20 MW or less in nominal capacity. With a substantial amount of past ETO renewable energy funds devoted to projects above 20 MW, the legislation means that the ETO will have to reorient its renewable energy programs to specialize solely in smaller projects.

This report serves as a resource for the ETO and its stakeholders as they contemplate new efforts to expand the benefits of renewable energy for Oregonians. Specifically, this report discusses the state of several renewable energy technology markets that may serve as a source of new renewable energy for the state though they do not yet represent a significant share of the state's energy mix: solar energy, wave energy, geothermal energy, and fuel cells with biogas. The report intends to introduce readers to the technologies, permitting issues, projects of note, and key suppliers.

The report concludes its sections on each technology with considerations for the ETO and its stakeholders for whether and how to expand the market for these technologies to benefit Oregonians, and specifically the ratepayers of ETO's main utility partners.

A couple of notes:

- First, to call geothermal an "emerging" renewable energy technology conflicts with a proven track record of large-scale geothermal projects in the West. However, the report does discuss an emerging small-scale geothermal technology that is just beginning to attract attention. And for the state, the installation of any new project could represent the emergence of a promising energy resource that has not yet established itself locally.
- Second, the report focuses most of its attention on solar and wave energy for several reasons. "Solar" encompasses numerous technologies that require extensive discussion to understand their markets. Wave energy activity is focused on Oregon, and interest in the state plus the novelty of the technology and its permitting issues merit an extensive discussion. Geothermal energy is relatively well understood, and the ETO has been involved in identifying potential projects in the state. Finally, the market for fuel cells with biogas is not particularly active, though several trends are worth considering.

The report benefitted tremendously from interviews with many market observers and participants who are noted at the end. It also benefitting from review from Peter West, Justin Klure and Kevin Banister. However, the author takes full responsibility for the final content of the report.

SOLAR ENERGY

INTRODUCTION

The solar power industry has experienced a dramatic, global expansion in the past 10 years. Most of this growth has occurred in photovoltaic (PV) capacity in distributed applications close to their point of use. A part of this growth has been the substantial investment in central station solar power -- something that has not happened since the 1980s and 1990s when several solar thermal plants emerged in Southern California.

This renewed interest in central station solar power is the result of several factors: (1) renewable portfolio standards (RPSs) with very aggressive targets (California); (2) RPSs with a required solar "carve-out" (Nevada and Colorado) or extra credit for solar (New Mexico); (3) the federal investment tax credit, which is currently set at 30% of the cost of a system; (4) high market clearing prices, particularly for peak periods (California, Arizona and Nevada); (5) concerns about the diminishing availability of good sites for competing renewables such as wind (due in part to transmission constraints, such as in California); and (6) ambitious subsidy policies overseas that have spurred an influx of capital, project experience and new companies (Spain and Germany).

Since the Energy Trust already provides incentives for distributed PV systems in Oregon, the focus of this section is on central station solar power, and more specifically:

- What are the technologies on the market, and what are their performance characteristics, opportunities and challenges, and permitting requirements?
- Where is central station solar power being developed?
- Why is development occurring in certain regions versus others?
- Who is manufacturing technologies and developing projects in the U.S.?
- What are some key considerations for the Energy Trust of Oregon (ETO) and the State of Oregon to attract new central station solar generation investment and development to the state?

TECHNOLOGY BACKGROND

Basic Description

Technologies for central station solar generation come in four main forms:

Parabolic trough — Parabolic trough plants feature concave, single-axis mirrors with an east-west orientation that focus solar energy on glass vacuum tubes. The tubes carry a heat transfer fluid (HTF) such as oil. The fluid can heat to over 700 degrees Fahrenheit to heat steam that powers a steam generator. Steam then runs through a condenser with wet cooling or dry cooling, and then begins the process again by running through heat exchangers. Parabolic trough plants can include solar energy storage capabilities (e.g., concrete, molten salt and thermocline storage) that can extend generation by less than an hour to several hours.

Parabolic trough plants can also include fossil fuel to generate steam. The fossil fuel component backs up solar electricity generation. It also can extend the capability of the plant to cover load during periods of "direct normal insolation" (DNI), which is solar insolation not dispersed by clouds or haze.

Power tower — Power tower plants consist of many individual, two-axis mirrors (heliostats). The heliostats track the sun to direct solar energy to a receiver, which is located at the top of a tower in the middle of the heliostat array. The receiver can contain water to generate steam directly, or it can contain molten nitrate salt as an HTF that can heat up to over 1,000 degrees Fahrenheit. The molten salt HTF then produces steam,

which powers a turbine for electric generation. Molten salt offers a ready source of energy storage for up to 12 hours to provide back-up generation during periods when DNI is not available.

Dish Stirling — Dish Sterling technology uses a two-axis parabolic dish that concentrates solar energy onto a receiver located at the dish's focal point. The receiver contains a Stirling engine that uses a gas (often hydrogen) that is heated and cooled to drive pistons and create mechanical energy. The mechanical energy drives an electric generator.

Photovoltaics — Photovoltaics produce power when solar energy dislodges electrons from one layer of silicon. The displaced electrons then run through a circuit to reach another silicon layer. Central station photovoltaic plants are composed of many photovoltaic modules aggregated together. One form of central station photovoltaic plant can consist of concentrating photovoltaics, which feature lens or mirrors that concentrate solar energy on to modules.

Performance Characteristics

Table1. Compares the four technologies based on several key performance characteristics

Technology	Trough	Tower	Dish Stirling	Photovoltaic
Cost (including existing federal incentives)*	Capital: $3.9/Wp O&M: $0.06/W-yr	Capital: $4.16Wp O&M: $0.03/W-yr	Capital: $6/Wp O&M: $0.12-0.20/W-yr	Capital: $5/Wp O&M: $0.05/W-yr
Modularity	Low – initial generator investment limits flexibility; industry participants prefer projects 30 MW and higher	Low – initial generator investment limits flexibility; industry participants prefer projects 50 MW and higher	High - "all-in-one" dish systems provide flexibility, with dishes rated from 3 kW to 50 kW each	High – no generator needed and adding of modules to a system is relatively easy
Commercial status	Large-scale commercial projects up to 80 MW each in place	Only one operating plant at 10 MW with another to come	No experience in large-scale projects; currenty being tested with individual systems	Mature for plants under 10 MW and limited for larger plants
Storage/dispatch	Solar energy storage and/or fossil fuel component optional	Embedded in plants with molten salt; fossil fuel component optional	No plants in place with storage capability	Infeasible due to lack of economic battery storage options
Engineering, procurement and construction (EPC) complexity	High complexity particularly with storage and/or fossil component; experience with several plants in U.S. and overseas	High complexity and minimal global experience	Individual systems are relatively simple, but no global experience with large-scale projects	Low - feasible to use "off-the-shelf" EPC firms; substantial global experience with increasingly larger plants

Permitting complexity	Non-fossil: Medium (building, conditional land and water use, waste) due to water use and oil HTF component Fossil: High due to water use, oil HTF and air emissions; land footprint at 5 acres per MW	High (building, conditional land use, water use, waste) due to water use and tower height; land footprint at 5 acres per MW	Medium with no fossil fuel and attendant air permitting; water use, conditional land use for large central station plant applications; land footprint at 3.8 acres per MW (40 25-kW systems per MW)	Low due to no fossil fuel and very limited water consumption (for cleaning modules); building-integrated options minimize land footprint but entail additional building permit issues
Water needs	Water required for steam and cooling in amounts similar to conventional steam plants; dry cooling is possible at 10% extra cost	Water required for steam and cooling in amounts similar to conventional steam plants; dry cooling is possible at 10% extra cost	Minimal need to clean dishes	Minimal need to clean modules

*Navigant Consulting. *Levelized Cost of Generation Model – Renewable Energy, Clean Coal, and Nuclear Inputs.* IEPR Committee Workshop on the Cost of Electricity Generation. Sacramento, Calif. June 12, 2007. Power tower costs based on George Simon. *Developing Cost-Effective Solar Resources with Electricity System Benefits* (California Energy Commission, 2003) report written for the the California 2005 Integrated Energy Policy Report.

Cost Reduction Potential

Central station solar power technologies are more expensive than competing renewables such as wind, and cost more than fossil fuels such as coal and natural gas. Cost reductions are essential to help grow these technologies. For all of the technologies above, experts believe cost reductions will come about due to:

- Learning in project design and operation due to market growth
- Reductions in manufacturing costs due to expanded capacity in response to market growth
- Incremental improvements in component design and configuration
- Plant economies of scale due to larger capacity

The first two factors depend on market expansion. Without market expansion, hoped for cost reductions will be less dramatic. A review of two studies of both troughs and towers – one by Sargent and Lundy for the National Renewable Energy Laboratory, and another by Sandia National Laboratory's SunLab – finds that it is plausible to see cost reductions by 2020 of over 50% if markets expand, and research and development (R&D) efforts succeed. However, absent significant market expansion, 2020 costs will be much higher.

It is important to note that few foresee radical change in technology for troughs, towers and Stirling engine technologies. While governments are renewing their attention to solar thermal R&D, a decade of relative dormancy in solar technology investment tempers predictions of dramatic cost and performance improvements. Instead, incremental improvements in the efficiency of solar energy capture and conversion can drive steady cost declines. For troughs, receiver performance improvements can increase energy-to-thermal conversion by 20% and improved HTF pump to reduce parasitic load. For towers, lower-cost heliostat design, improved controls of heliostats to increase solar energy capture, and the emergence of supercritical steam turbines could reduce costs.

A variation on trough technology involves compact Fresnel lens collectors. Fresnel lens are parallel lenses that are flat on a slightly curved frame, which intensify light similar to a lighthouse lens.. Fresnel lens collectors focus light on a receiver that feed into closed loop boiler tubes in which steam is separated and sent to a turbine. Steam temperatures are not as high as those for more common trough technology, but capital and O&M costs are lower, while water serves as the HTF instead of oil. The ability to concentrate light allows Fresnel lens trough projects to be placed in areas with lower DNI than other trough plants. Ausra of Australia has installed a 6.5-MW plant in Portugal, and is installing a test plant in Australia that helps power a turbine at a coal-fired plant. The absence of oil and lower water use reduces permitting tasks for water use and air emissions.

PV is poised for cost reductions due to worldwide expanding module manufacturing capacity. Incentives in the U.S., Europe and Japan, associated demand growth, current supply shortages, and an influx in capital make PV most likely to decline in cost. Continued improvements in energy conversion efficiency and cell manufacture to reduce dependence on silicon are also likely; due to relatively high levels of R&D funding compared to solar thermal technologies. The European Photovoltaic Industry Association projects a steady reduction of silicon per cell, coupled with higher cell efficiencies, with efficiencies growing from 14% in 2003 to 17.5% in 2010. In addition, wafer thickness is projected to decline by over 50% during that time.

SOLAR THERMAL PROJECTS

There are numerous solar thermal projects worldwide. Most existing solar thermal projects are in test beds such as Sandia National Laboratory's facility in Albuquerque, N.M., and in Almeria on Spain's south coast. While such demonstrations are essential for market development, the focus here is on operational projects built to serve electricity demand on a commercial basis, and on high-profile projects that represent important advances in demonstrating technical feasibility.

Existing Projects in the U.S.

SEGS

The first large-scale trough projects still in operation are the Solar Energy Generating Systems (SEGS) plants. Located in California's Mojave Desert near Barstow, nine individual plants ranging from 14 MW to 80 MW offer a combined capacity of 354 MW. Luz International installed the first units in 1984, completing the last unit in 1990. The units include gas generation.

Sunray Energy now owns SEGS I and II, while FPL Energy and Carlyle Riverstone own SEGS III-IX. Southern California Edison is the power purchaser. The SEGS plants have run consistently since their installation, with levelized power costs estimated to be 24 cents/kWh for SEGS I and II, and as low as 12 cents/kWh for the other units. The solar-only component costs close to 16 cents/kWh. An official close to the plant's operations estimates the solar-only capacity factor to be between 26% and 28% for the more recent SEGS units.

California's high avoided-cost rates under the Public Utility Regulatory and Policy Act (PURPA) spurred the installation of the SEGS units. The availability of peak power also was a factor.

Nevada One

Solargenix developed the 64 MW Nevada One trough plant in Nevada, which began generating power for the grid in 2007. Solargenix has a PPA with Nevada Power for the plant output, which will help Nevada Power meet its state RPS obligations. The plant includes a natural gas component that may supply about 2% of the plant's total output by heating water for its 75 MW steam turbine. The Nevada One plant is the first, large-scale CSP plant in the U.S. since the startup and shutdown of Solar Two power tower in 1994.

The state RPS is the key driver behind Nevada Power's interest in the plant. The state RPS requires 20% of power serving in-state customers to come from renewables, with a minimum of 5% of acquired renewable energy to come from solar energy.

Saguaro

Solargenix built the 1-MW Saguaro trough plant in Springerville, Ariz., for Arizona Public Service. The plant serves as a demonstration project supported in part by $6.5 million in rate-based R&D funding from APS, which purchased the plant assets.

The small size of the plant is indicative of its demonstration purpose, and neither APS nor Solargenix have expressed interest in replicating it at plant scale. Rather, there is now interest in pursuing larger plants at 50 MW and higher.

APS' interest is due to the Arizona energy performance standard (EPS), which requires 15% of utility load to be served by renewable energy by 2025; along with interim targets. With abundant solar energy and high summertime demand peaks in the region, APS hopes that solar thermal technology will continue to develop and become a reliable, low-cost renewable resource to meet its targets. (An earlier version of the EPS included a solar-specific target, but revisions eliminated that component and opted for a "carve-out" for distributed resources instead.)

Existing Projects in Europe

The only significant solar thermal generation project in Europe is a 10-MW PS10 tower plant near Seville in southern Spain. Abengoa of Spain developed and built the plant, which came on line in 2004. The plant uses a saturated steam receiver rather than a molten salt receiver in the power tower. The steam option is considered a lesser technological risk than the molten salt option, though observers see the latter as the technology's future due its storage capabilities. The plant does include a small water thermal storage component fed by the power tower, and is drawn upon to supply 20 MWh of power to the generator. The storage power's main benefit is to avoid excessive steam turbine shutdowns and start-ups. The plant includes 624 heliostats and a 115-meter-high (377-feet-high) tower.

Spain's incentives are the main driver for the plant. Incentives include an electric feed-in law, set at 18 euro cents/kWh at all times, as well as European Union and state government subsidies for the plant totaling 6.2 million euros. Abengoa plans to build a 20-MW power tower near the PS10 site, which will be operational in 2008.

Upcoming Projects

California

In California, both San Diego Gas and Electric and Southern California Edison have announced their intention to enter into PPAs with several solar thermal projects under development. PG&E is pursuing joint solar project development, and other major public utilities also are pursuing solar thermal projects. The aggressive state renewable portfolio standard (20% of IOU loads to be served by renewables in 2010, with the same target intended for public utilities) spurred utility interest in the projects. The lack of other strong renewable energy opportunities in the transmission-constrained state also has pushed solar project bids ahead of wind projects. Finally, utilities appear to value the coincidence of solar power generation with peak demand periods, as well as the potential capacity value for plants with backup power or storage.

Dish Stirling. Stirling Energy Systems announced a 300-MW PPA with SDG&E with an option for another 500 MW based on a project near Calexico, Calif. It also announced a 500-MW PPA with SCE, with an option for another 350-MW project near Victorville, Calif. The projects would consist of dish Stirling arrays in the Mojave Desert. The plant for the 300-MW PPA would consist of 12,000 25-kW dishes, while SCE PPA would consist of 20,000 dishes that would offer a 24% capacity factor, according to the developer.

Most observers are highly skeptical that the promised plants will be built. This skepticism is based in part on speculation that the bidding price under 10 cents/kWh was too low. More important is the concern that there isn't a large-scale, solar dish Stirling plant to provide operational experience. Plus, there's a need for an engineering, procurement and construction (EPC) wrap for affordable debt financing. The CPUC approved the contracts, but negotiations between the utility and the developer continue.

Trough. SDG&E also announced a 100-MW PPA with Bethel Energy, a small, California-based development company founded by a former SEGS developer and operator. The company intends to supply two 50-MW units with an oil HTF and up to an hour of solar thermal storage. They also plan to heat the HTF with biogas derived from cow manure in Southern California's Imperial Valley. Its steam is capable of providing 24 MW of capacity. The back-up energy contributes to an overall capacity factor of over 60% to cover both peak and "mid-peak" hours in the morning and evening.

Power tower. PG&E signed an MOU with Bright Source, a power tower developer, to explore the joint development of a 20-MW project. Bright Source consists of former Luz employees. The project reportedly will eschew molten salt receiver technology in favor of less risky and lower efficiency steam receiver technology.

Rocketdyne, a former Boeing unit now owned by United Technologies Corporation, proposed an 80-MW tower plant with a steam receiver to the Los Angeles Department of Water and Power's recent RFP. LADWP will make short-list decisions in late 2007.

Activity Elsewhere in the U.S.

A group of at least seven southwest utilities have formed a consortium to pursue 250 MW of central station solar power plants, both single and multiple plants. The consortium consists of Arizona utilities such as APS, Salt River Project and Tucson Electric, with interest from Xcel, Public Service of New Mexico, Nevada Power and others. All face state RPSs and serve states with high DNI resources. Observers recognize challenges such as different location requirements in the various state RPSs governing the region, plus the inherent complexity of joint investment from utilities governed by different public utility commissions and boards. At least one employee of the involved utilities foresaw a potential cost of 14-16 cents/kWh over 25 years with gas backup for a large plant.

New Mexico has made a concerted effort to pursue central station solar thermal projects. The state's Energy, Minerals and Natural Resources Department has commissioned studies examining technology options and economic development benefits. The effort follows Governor Bill Richardson's 2004 executive order that established a task force specifically focused on concentrated solar power. The state's RPS also credits solar with three times the RPS-eligible renewable energy credits, compared to wind generation and 1.5-times biomass and geothermal generation.

Europe

Spain is the dominant market for solar thermal development in the world, with the western U.S. its closest

competitor. The Spanish feed-in tariff is currently set at 18 euro cents per kWh. This drives deveopment since solar plants enjoy a tariff up to three times the "average reference tariff" in the nation. The tariff is available to projects for 25 years of operation. Additional subsidies include financing from the European Union that covers project risk, which is important for a market that had not seen a new commercial project in 10 years. By 2006, developers were touting more than 500 MW of projects in southern Spain ready for construction, though currently the PS10 power tower project is the only project online. Others are expected to follow next year.

Solar Millenium Group, from the Germany and Spanish engineering firm ACS Cobra, own the rights to the AndaSol trough project in southern Spain, which is estimated to comprise three 50-MW units in 2008. ACS Cobra, Spanish engineering firm SENER, and German FlagSol are providing engineering, procurement and construction (EPC) services for the plant, the first large-scale trough plant in Europe and the first anywhere with molten salt storage.

Also, Abengoa is in the process of developing a second power tower plant next to the PS10 plant in southern Spain. The new plant will feature molten salt receiver technology rather than the proven steam receiver design of PS10. Sener, a Spanish aerospace firm, is developing a power tower project with a 17-MW molten salt receiver.

Iberdrola, the Spanish utility and independent power producer, claims to have 500-MW of trough projects in its pipeline, with 50 MW ready for construction in New Castile. Abengoa's Solucar touts 300-MW of trough projects under development in Spain.

LARGE-SCALE PV PROJECTS

PV markets have grown steadily over the last 10 years, due to generous subsidies in Germany and Japan, as well as more recent aggressive subsidy policies in California. Applications vary from off-grid (e.g., cathodic protection for gas pipelines and remote telecommunications) to less economic grid-tied applications. The latter type includes very small systems (under a kilowatt) to large plants, though the latter form of grid-tied PV is a more recent phenomenon. Generous feed-in laws in Europe and investment subsidies in Japan have encouraged development of large PV generation plants. In Europe, there are at least four PV plants at 10 MW or higher that are located in Germany and Portugal. Spain houses numerous projects over five MW. In Japan, Sharp installed a plant over five MW at its recently built manufacturing facility.

The U.S. is starting to see large PV projects develop, particularly in the western U.S. California is the most robust state market with over $3 billion in available subsidies and net metering for projects up to 1 MW. Since 2006, subsidies were available to up to the first MW of a PV plant, the impact may not include the development of large plants as in Europe, but many projects located near load and sized at 1 MW or slightly higher are coming online.

Outside of California and in the West, several projects stand out for their size, technology and/or utility involvement:

Alamosa, Colorado. SunEdison of California developed an 8.2-MW PV plant in response to a solar RFP from Xcel Energy. The Alamosa project is a combination of concentrating PV and flat-plate PV. Chinese-owned Suntech manufactured the modules while German Solon AG supplied the concentrators. SunEdison entered into a PPA with Xcel.

Xcel's RFP was a direct response to Colorado's RPS, which requires 4% of the utility's renewable energy supply to meet the RPS to come from solar energy. While Xcel also provides incentives to adopt PV and meet the mandate, it felt that a merchant PPA approach would help guarantee power to meet its obligations, rather than

solely relying on customer adoption. The quick release of the RFP may have precluded well-developed solar thermal project proposals, which resemble wind power proposals in the need for extensive land rights, resource measurement and project design work.

Arizona Public Service PV projects. APS owns or buys the output from numerous PV plants. The most prominent project is the 3.5-MW Prescott, Ariz. project consisting of both single-axis tracking with flat-plate PV, and two-axis tracking with concentrating PV to maximize solar energy capture. APS owns the plant, oversaw construction and provided up-front funding from a rate-based fund that supports research, development and demonstration. Arizona-based Amonix designed the two-axis PV systems, sized at 33-kW each, while the single-axis systems were designed by WorldWater and Power. A total of over 600 kW of Amonix's two-axis PV systems exist elsewhere on APS's system, including a 100-kW project in Glendale.

APS had numerous reasons for supporting the PV projects. APS has traditionally invested R&D funds on solar technologies, including a test center in Tempe that houses a changing portfolio of technologies. The original Arizona EPS included a preference for solar in an effort to become a national leader in solar technology. The more recent EPS does not include a specific solar requirement, but APS still sees solar as a key resource to meet skyrocketing peak loads, meeting the EPS and addressing the state's special interest in solar.

Nellis Air Force Base, Nevada. The U.S. Air Force conducted extensive site preparation and ran a supplier RFP for a planned 15-MW PV project on Nellis Air Force Base in southern Nevada. The PV plant, to be the largest in the U.S., will supply Nellis' load while also helping to meet Nevada Power's RPS obligations. California-based SunPower, including its subsidiary PowerLight, is supplying modules and EPC services for the single-axis tracking project. MMA Renewable Ventures, a clean energy investment group based in San Francisco, is financing the plant and will own the plant while supplying power to the base under a PPA.

INDUSTRY PARTICIPANTS IN THE U.S.

The structure of the central station solar industry reflects the market maturity of the different solar technologies involved. The solar thermal industry consists of more vertically integrated firms that began as manufacturers or as EPC service providers, who then moved downstream (in the case of manufacturers) and upstream (in the case of EPC providers) into project development. Vertical integration reflects two main considerations: First, the market is still too small for firms to focus on specializing in individual parts of the industry value-chain. Second, firms with the technology experience are acting as first movers to launch new projects in order to capture more value.

There are very few solar thermal key component suppliers, which reflects the small market scale and lack of incentive for new entrants. Observers generally do not view this as a problem for the industry, as they believe that component suppliers can meet market growth with expanded production. As seen in other sectors, such as wind and PV, growth should attract new entrants.

Trough suppliers and/or developers

Acciona Solar/Solargenix LLC. Acciona Solar developed and manufactured the mounting frames of the 64-MW Nevada One trough plant that came online this year. Acciona Energy, a Spanish independent power producer owned by Spanish industrial group Acciona, purchased a 55% share of Solargenix from Duke Energy in 2006. Solargenix LLC holds the remaining 45% of Solargenix. (In May 2007 Solargenix LLC announced an MOU with World Water and Power to combine marketing and joint technology offerings in the solar market.)

Abengoa. This large Spanish firm that manufactures mounting systems and provides EPC services to the power industry. Abengoa formed the Solucar subsidiary to focus on solar thermal development both in troughs

and power towers. The company developed the 10-MW PS10 power tower plant near Seville, Spain, and is developing another plant nearby. In the U.S., it rapidly has hired personnel from federal laboratories and veterans from the previous spate of solar thermal plant development in the U.S., and has located its headquarters in Golden, Colo.

ACS Cobra. Another large Spanish EPC provider, ACS Cobra is developing a large trough plant in southern Spain and is also ramping up U.S. development operations.

FPL Energy. Known more as a wind power developer, FPL Energy owns seven SEGS units in Southern California and is developing other sites in the southwest U.S.

Ausra. A vertically integrated firm from Australia, Ausra is the only plant designer and developer focused on Fresnel lens technology for trough plants. It fabricates solar arrays and also operates plants with a preference to own. Ausra has received capital from the Silicon Valley venture capital firm Kleiner Perkins and information technology entrepreneur Vinod Khosla. Its U.S. operations are based in Palo Alto, Calif.

Bethel. California-based Bethel is a small developer of trough plants whose interest in biogas backup differentiates it from other developers and plant designers. Len Daniel, a former developer and operator of the SEGS units, leads the company. Though it is small, its 100-MW PPA with SDG&E gives Bethel as good a chance as any other developer to bring the next U.S. solar thermal power project online in the near future.

Solar Millenium. German firm Solar Millenium develops and constructs trough plants, with a focus on Europe, China and the U.S. Solar Millenium attracted GE Energy Financial Services to buy 80% of the shares of a subsidiary with a pipeline of five projects. The company has not yet developed a plant but has a U.S. presence and is actively prospecting for sites in the southwestern U.S. Solar Millenium also owns two component manufacturers Flabeg and Smagsol.

Solel. Israel-based Solel is the leading manufacturer of solar collectors for trough plants, including the Nevada One plant. It also develops projects, and has entered into a PPA with PG&E for a 553-MW trough project in the Mojave Desert, scheduled to be online in 2011.

Schott. Schott is the leading manufacturer of glass tubing for transferring solar radiation to heat-transfer fluid and circulating the HTF through the plant. Schott supplied tubing to the Nevada One plant.

Centrosolar. Though its primary market is as a glass supplier to the PV industry, Spanish-owned and German-based Centrosolar (formerly Flabeg) manufactures glass covers for solar collectors of trough plants.

Siemens and Ormat. Though better known as a global energy technology leader and a geothermal plant generator provider, respectively, Siemens and Ormat have supplied steam generators for solar thermal plants in the U.S.

Power tower suppliers and/or developers

BrightSource. Founded by ex-Luz executives involved in the original Solar One and Solar Two power tower projects in the 1990s, BrightSource is working with PG&E to explore the feasibility of a series of steam receiver power tower projects in Southern California, including a site near Victorville. BrightSource is also pursuing a pipeline of 300 MW of power tower projects.

Rocketdyne. A former creation of Boeing and now owned by the Pratt and Whitney division of United Technologies Corporation, Rocketdyne has proposed a 80-MW steam receiver plant to LADWP.

Sener. Spanish aerospace firm Sener is developing the "Solar Tres" 17-MW power tower project with a molten salt receiver in southern Spain. Sener worked closely with Rocketdyne to design the molten salt receiver.

Nexant. A San Francisco-based engineering firm, Nexant is deeply involved in power tower project design in the western U.S.

Dish Stirling suppliers/developers

Stirling Energy Systems. Phoenix-based SES gained attention when both Southern California Edison and San Diego Gas and Electric announced PPAs of 500 MW and 300 MW, respectively, with the solar dish sterling manufacturer and developer. SES holds patents originally held by McDonnell Douglas and runs several dish Stirling systems at Sandia National Labs' solar energy test center in Albuquerque.

Infinia. Based in Kennewick, these manufacturers of Stirling engine systems recently received $9.5 million from Vulcan Capital, Vinod Khosla, and other VC funds. Infinia is focused on a 3-kW solar dish Stirling product, making it more appropriate for smaller and more distributed applications. It plans to complete a prototype system later in 2007.

PV Industry Participants

The PV industry is more mature than the solar thermal power industry due to steady and rapid market growth in Europe, Japan and the U.S. In the U.S., leading developers of systems 1 MW and higher include California companies SunPower (including PowerLight), El Solutions and SunEdison, which have installed large systems. Others in California have developed systems below 1 MW but likely are capable of developing larger systems. The California Solar Energy Industries Association has 105 contractors as members.

New entrants into the PV market are arriving to meet projected high demand for larger PV systems, particularly in California. Opportunities exist in other western states and in the Northeast, where incentives and mandates drive growth. New entrants include German companies Conergy and Optisolar, as well as established wind IPPs such as enXco and PPM Energy..

Development strategies in the PV industry include both greenfield development for stand-alone PV arrays (e.g., the Alamosa, Colo. project), as well as large installations on commercial and industrial rooftops. Large rooftops are becoming the basis on new product models and is the subject of heated interest among developers. In California, several policies have encouraged ambitious business plans among developers. The state's $3 billion subsidy program supports up to 1-MW of capacity per project. Net metering capped at 1 MW per interconnected project is also boosting interest among developers and rooftop owners. The availability of the 30% federal investment tax credit (ITC) opens up investment strategies involving tax equity investors and merchant ownership of PV systems. Developers such as SunEdison are creating new products in which the developer and/or other tax and equity investors own the PV system, offer a flat rate to the rooftop owner.

PV manufacturing capacity has struggled to keep up with demand, due in part to a "wait-and-see" approach to subsidy-driven markets, as well as a global shortage of PV-grade silicon. The traditional focus on crystalline silicon PV has shifted towards thin film PV that uses less silicon though at a higher cost. However crystalline silicon PV still dominates the market. Planned production expansion, including two new PV plants expected in and around Portland, Ore., will reduce the supply bottleneck.

Leading cell manufacturers include Sharp, Sanyo and Kyocera of Japan; Suntech of China; Q-Cells, SolarWorld

and Schott of Germany; BP Solar of the UK; and Evergreen, First Solar and SunPower in the U.S., with many others with existing or planned operations.

CONSIDERATIONS FOR ETO

Oregon's solar resource dampens interest but does not preclude development

Oregon's DNI resource is not comparable to DNI in the southwest, except for southern Oregon east of the Cascades, where insolation is approximately 6-6.5 kWh/m/day. Compared to levels of 7-8 kWh/m/day in Arizona, California, Nevada, New Mexico, Colorado and Utah, southern Oregon's resource could represent to cost increase of up to 25%, not considering load coincidence and the associated market value of the power.

Systems that can maximize access to solar energy and solar-power conversion efficiencies can help mitigate Oregon's more limited resource. Because of Oregon's high latitude , two-axis PV tracking systems that can move north-to-south as well as east-to-west are best suited to maximize access to DNI compared to a single-axis tracking system, such as a trough plant with just an east-west orientation. Power tower heliostats on 2 axes can also obtain more DNI. The usual tradeoff between advanced tracking and simple systems, such as flat-plate PV and troughs, is greater O&M complexity, including tracking controls and repair of failed tracking systems.

It is important to note that PV does not have the same need for DNI as solar thermal systems do, as they can still convert more dispersed insolation into power. This makes PV a more flexible technology for economic siting in the state.

The federal investment tax credit (ITC) is essential for financial viability of solar thermal projects, but not necessarily for PV, particularly with a 50% BETC in place

The federal investment tax credit, which applies to 30% of a project's capital costs, is an essential financial piece for any major solar thermal project in the U.S. today. All observers interviewed believe that the solar thermal power industry would go away if the ITC expired permanently. In short, the ITC is like the wind production tax credit in its importance potential transience. The unpredictability could lead to similar “boom-bust” cycles in the solar thermal industry as in the wind industry.

Financiers do not necessarily see the ITC as essential for PV growth, given low financial risk for a proven technology and beneficial policies such as PV rebates and net metering. In Oregon, a Business Energy Tax Credit sized at 50% (with a maximum of $10 million per project) of a 20-MW or less project would have a bigger impact than the ITC, and would benefit commercially feasible scales for both PV and dish Stirling projects.

Utilities cannot use the ITC today. Consequently, the ITC needs to attract nonutility financing such as tax equity to impact a project. The size of the ITC is successfully bringing tax equity financing into the solar industry, particularly when coupled with federal accelerated depreciation over the initial five years of a project's life.

Southern Oregon offers power marketing opportunities to other states, though the marketing clearing prices in those states will pose tough competition for the ETO

While the region in Oregon with the best DNI is not near population centers, it is located next to two states – California and Nevada – with aggressive RPSs and utilities with solar technology experience. Transmission access to the three 500-kV transmission lines from Captain Jack and Malin into California, and to the 500-kV

DC line above the Nevada border for export to Nevada and California, offers challenges (congestion and very high voltage interconnection) and opportunities (greater incentives, along with new potential wind development, to expand transmission capacity).

Also notable is PacifiCorp's proposal to build a new transmission line from the Idaho-Oregon border to the Oregon-California border. The line would cross through the heart of Oregon's high-DNI region. If connected to a liquid point on the California border, the line could open project opportunities in central Oregon currently unavailable due to limited transmission.

In sparsely populated southeast Oregon, only one transmission line – a 115-kV line owned by Harney Electric Cooperative – serves the region. The benefit of the line is its direct connection to Sierra Pacific transmission in northeast Nevada and attendant opportunity to serve Nevada's RPS-driven demand for solar energy. However its ability to accommodate a new solar project is constrained by its small capacity and a possibile new wind power project coming online. The federal government included the line's right-of-way in its Preliminary Draft Westwide Energy Corridor Programmatic EIS for expedited siting of new energy infrastructure.

Both Nevada and California require the delivery of green tags for power to qualify for RPS compliance. The requirement may clash with ETO's current policy of securing tags in association with its support for projects . If a project is to serve out-of-state RPSs as well as receive ETO support, it will need to balance its tags delivery to the ETO and to complying entities out of state.

For an ETO subsidy to help make a project happen, its support for at least a portion of a plant's output would have to be greater than what the project owner would be able to receive from other entities complying with state RPSs. For reference, California's "market price" for renewables is high relative to Northwest demand. The official market price referent (MPR) for California's RPS ranges from $78/MWh to $93/MWh depending on the online date and contract term. (The 2006 MPR for a 20-year contract began at $84.60 in 2007 with escalation thereafter.)

In addition to the MPR, the California Energy Commission can add a supplemental energy payment to renewable energy projects though it has not yet done so. (The CEC currently does not guarantee such "supplemental energy payments", or SEPSs, from year to year. The associated lack of financibility for such incentives has dampened developers' interest in SEPs. Between $700 and $800 million in SEPs are currently unspent). ETO may have to pay a substantial amount per unit of energy to receive green tags and make the subsidy meaningful relative to neighboring markets for green power.

Troughs and power towers will be large in scale with limited modularity

Different central station solar technologies have different degrees of modularity. The sizing of the generator block limits modularity for trough and tower technologies. For example, if a developer initially installs a 50-MW generator for a trough project, then any capacity to collect solar energy that falls below 50 MW leads to unused generator capacity and higher overall costs. Once the project reaches 50-MW in generation capability, further expansion will hinge on the size of the next generator, and so on.

None of the developers interviewed viewed unused generator capacity favorably. For power towers, the incorporation of the generator in the tower further erodes flexibility in sizing a plant — either the developer switches out the generator in the tower for further expansion, which is a potentially costly exercise, or another tower with another heliostat array is required.

For troughs and towers, developers and experts favor large-scale plants of at least 30 MW according to one developer and a minimum of 50 MW according to others. Such sizes provide economies of scale and efficiency

benefits based on many factors. For example, larger plants entail similar permitting and EPC challenges as smaller projects. EPC issues in particular are a challenge for the relatively small solar thermal power industry, since plants require exotic parts, such as receiver tubes that resist corrosion associated with high stress loads, and unique fabrication techniques. Smaller generators face more difficulty handling the high-temperature steam produced by solar thermal arrays. Conversely, larger generators can handle higher temperatures and steam pressure, raising overall plant efficiency. Doubling the capacity of a generator block presents cost increases far lower in scale. Plus, the ability to order more collectors and tubing also reduces input costs relative to a smaller array. One expert estimates that a 30-MW trough plant could be 50% higher in cost than a 100-MW project, with a 100-MW plant roughly costing 13-16 cents/kWh.

While a 50% cost above that range does not represent an outrageous cost for an emerging renewable technology, it does signal to the few solar thermal developers in the U.S. today to go to areas where they can execute large projects and improve their margins. So if the wind energy market is any indication, as the market grows, matures and induces new entrants, the interest in smaller plants will continue to wane as developers and EPC firms seek to maximize returns.

The 1-MW Saguaro plant in Arizona was based on the willingness of APS to execute a demonstration project to prove the viability of troughs after a decade of inactivity in the sector. The subsequent 64-MW Nevada One project is more indicative of the direction of the industry in the U.S.

Observers see the 10-MW PS10 project in Spain as halfway between a demonstration and commercial project, as Abengoa plans to gain operational experience with the plant as a prelude to larger projects in Europe and the U.S. The desire to replicate such scale is doubtful given the commercial leanings of project developers. The 80-MW Rocketdyne bid to LADWP is more likely the scale of future power tower projects in the U.S.

Senate Bill 838 limits ETO's leverage in incentiving new trough and tower projects

Oregon's Senate 838 (SB 838) may severely limit the ability of the ETO to support future trough and tower projects. SB 838, which mandates renewable energy supply for most of Oregon's electricity customers, also limits the ETO's involvement to projects 20 MW and below. Given the plans of trough and tower developers in the U.S. to focus on projects above 20 MW, the capacity cutoff may prove too restrictive for them to make Oregon a priority state for competitive projects based solely on the opportunity to receive ETO funding.

Dish Stirling and PV offer a better opportunity to ETO based on modularity and size

Though SB 838 may take ETO out of the commercial market for troughs and towers, it still leaves open the option to support dish Stirling and PV projects. Dish Stirling systems and PV are largely self-contained systems that do not rely on an external generator block, making them scalable without financial penalties associated with unused generator capacity. Nor, in the case of dish Stirling, do they require chunky ramp-ups in capacity due to conventional steam turbines. Finally, there is not an inherent generation efficiency benefit to larger scale as there is with larger generator blocks for troughs and towers, which can handle higher temperatures.

Therefore, while PV and dish Stirling developers appreciate the reduced development costs per unit of power due to large-scale projects, they are more likely to pursue projects below 20 MW since such a size does not erode their economics and resulting competitiveness in the power market. Oregon's business energy tax credit (BETC) supplies a strong incentive beyond the ETO to project developers, assuming it is set up to 50% of project costs with a maximum of $10 million per project.

The type of incentive depends on the maturity of the technology

Discussions with market participants and independent experts produced similar responses to the question of what incentives are necessary for market growth:

- Those involved in the more mature trough sector called for streamlined permitting, RPSs with a solar focus, a long-term federal ITC, and property and sales tax abatement.
- Those working in the tower sector frequently mentioned loan guarantees to reduce financing costs, in addition to RPSs and ITC extension. The interest in guarantees stems from the current lack of a readily available EPC wrap for tower projects in particular, due to the relative novelty of the technology and associated lack of experience among EPC providers. EPC wraps are a key factor for financiers when assessing project risks. Loan guarantees can help bridge the gap between the sector's current embryonic stage and future market expansion.

Technology risk will go down over time, though dish Stirling may have a longer way to go

Financiers raise more caution for technologies that have less commercial experience. For solar, that means that comfort is greatest for PV, followed by trough plants (with the long history of the SEGS plants) with higher levels of concern about power towers and dish Stirling.

Yet for all of the solar central station technologies, perceived and real technology risk should decline over time as more projects materialize, EPC firms gain more experience, permitting agencies become more familiar with real and perceived impacts, and financiers consequently attach lower risk to technologies with proven performance.

For PV and to a lesser degree troughs and towers, market growth is based on new project development, interest among utilities in pursuing the technology, the financial and experiential heft of leading market participants, and supportive policies in the U.S., Europe, and Japan (in the case of PV).

Dish Stirling does stand out as a technology with minimal commercial experience and very few suppliers. The proposed projects in Southern California for SCE and SDG&E are the only known near-term opportunities for dish Stirling projects. The modular nature of dish Stirling technology does offer hope that without California projects, other projects at smaller scales are feasible in the near-term to raise comfort with the technology's reliability.

Power tower and trough projects face higher development thresholds than dish Stirling and PV

Efforts to provide incentives for trough and tower plants in Oregon will have to take lead-times into account, particularly since no in-state development activity is apparent. Trough and tower projects entail many permitting steps related to land use, building, air quality and possibly for water use and waste. At approximately five acres per MW of capacity, trough and tower projects are similar in scale to wind farms and therefore require substantial land. Developers also must conduct a year's worth of onsite solar resource assessment, similar to a year's worth of onsite wind data for prospective wind projects.

However, trough and tower projects have added permitting requirements. A fossil back-up component can trigger air permitting. The oil-based HTF can trigger permitting under the federal Resource Conservation and Recovery Act. Steam generation and wet cooling adds water use permitting requirements. Permitting for power towers themselves can raise Federal Aviation Administration concerns due to their prominent height (377 feet).

Consequently, for projects to materialize in Oregon, developers must invest substantial development lead times. The complexity of permitting raises the opportunity to incent trough and tower plant developers through streamlined permitting processes, particularly if the process is less onerous than in neighboring markets in California and/or Nevada.

PV and dish Stirling, which do not require oil-based HTF nor fossil back-up, and can exist in smaller project scales requiring less land, offer quicker project lead-times than trough and tower projects. Faster project cycles mean that PV and dish Stirling developers could respond quickly to utility RFPs, as in the case of the 8.2-MW PV project for Xcel in Alamosa, Colo. A program to support these technologies rather than trough and towers would not rely on lengthy lags between program inception and project bid maturity.

The Northwest's power market context will determine the need for storage and backup

The question of whether to add storage and/or back-up capabilities to central station solar projects depends on the value that those capabilities add to the project's economics. In Spain, the availability of the feed-in tariffs at all hours of the day spurs developers to add storage and backup to increase output. In the southwest U.S., the high cost of serving peak (over $100/MWh) and mid-peak loads also encourages developers to examine storage and back-up options. Capacity credit is also more likely with backup.

However, for troughs in particular, storage represents significant cost. One study by Black and Veatch for the National Renewable Energy Laboratory (NREL) looked at a hypothetical trough plant to be built in California in 2009. The study estimates that storage components such as tanks, heat exchangers and six hours worth of storage fluid can represent 12% of project capital costs and up to 15% of total project costs. (The costs are based on a breakdown for a 2007 100-MW trough plant with 6 hours of storage, with total cost based on breakdown for a 2009 100-MW trough plant with 6 hours of storage.) Another study, by Sargent and Lundy for NREL, estimates that 12 hours of storage represents 23% of total direct costs for a 100-MW plant.

In the Northwest, the power market may be less amenable to storage and back-up generation. At least one utility active in the solar thermal market in the West is skeptical about the ability of solar thermal projects to provide lower-cost capacity compared to the utility's ability to address intermittency with owned and purchased resources. The Northwest’s hydropower is relatively low in cost compared to gas-fired generation. Low-cost hydropower can discourage storage and back-up in a solar thermal project that normally serves to displace high-cost peaking plants. The lack of sharp demand peak in the region also hurts the economics of storage and backup, though the ability of a plant to export power to markets in California can mitigate the relative smoothness of Northwest demand patterns.

It is important to note that another benefit of storage is to avoid generator shutdowns and startups when the solar resource is not available, thereby boosting efficiency.

WAVE ENERGY

INTRODUCTION

Wave energy is in its infancy. Most of the attention in developing the technology is on West Coast where the resource is significant. This is especially true in Oregon, where developers are seeking to install the first generation of commercial projects.

This section will cover the basics of wave energy resources and technologies. It then describes numerous firms that manufacture wave technology and/or seek to develop projects in the U.S. Since permitting will be a major issue, this section also discusses permitting requirements and processes, which are still being developed. Since Oregon is leading the U.S. in nurturing wave energy projects, this section summarizes local institutions and stakeholders that will play an important role in project development.

Finally, there are numerous considerations for the ETO and others as they consider whether and how they should engage the emerging industry.

RESOURCE

Waves for power generation are created by wind blowing across oceans. Waves can carry for thousands of miles in the form of swell and eventually dissipate as they run into the shallow sea floor near the coast. Wave dissipation occurs through two actions: "Bottom drag" reduces energy through friction with the sea floor. "Refraction" occurs when the sea floor bends waves toward the coast and stretches them out along the shore. This reduces wave height along the crest to produce smaller wave rays close to the shore.

Wave energy can be expressed in watts per meter of a wave's crest. It has several key features:

- Seawater density, set at 1,025 kilograms per cubic meter.
- Wave acceleration, set at 9.8 meters per second.
- Wave period, or the spacing and timing between waves.
- Wave height, or "significant wave height," which is approximately equal to the height (trough to crest) of the one-third highest waves, being the key value. Wave energy is proportional to the significant wave height's square.

Wave variability can be viewed in five forms: (1) wave to wave on a second-by-second basis, (2) wave group to wave group on a minute-by-minute basis, (3) sea state on an hourly or daily basis, (4) seasonal on a monthly time scale, and, for multi-year energy projects, and (5) year-to-year including broader ocean-atmosphere factors such as El Nino.

Variability is more random from wave to wave. Variability between sea states, as expressed in average wave height and "dominant wave period" (the wave period with the greatest energy), is better understood by understanding underlying causes (e.g., deepwater storms) and observing measurement data. Annual variation can be significant — California, for example, has experienced a 50% change in wave energy levels annually.

Wave energy measurement draws upon several data sources and techniques:

- The National Oceanic and Atmospheric Administration (NOAA) operates deepwater meteorological data buoys and feeds data to the National Climatic Data Center for publication.
- The National Weather Service draws upon automated wave measurements closer to shore.
- The Scripps Institute of Oceanography, with funding from the U.S. Army Corps of Engineers, also operates data buoys largely on the Pacific coast as a part of its Coastal Data Information Program (CDIP). The CDIP also provides data processing capabilities to translate data into useful information for wave energy developers and others.

However, due to the relatively short history of the NOAA program, and the limited geographic coverage of the buoys, historical wave measurement also requires hindcast models that translate historical meteorological data into wave patterns. Hindcast models also forecast waves using weather forecasts. The U.S. Army Corps of Engineers' hindcast database, the Wave Information Study, is publicly available.

Along a coast, wave energy varies because of diverse sea floor characteristics that dissipate wave energy differently. Also, wave energy hot spots are created by concentrating energy near certain stretches of the coast. For the wave energy technologies currently planned for deployment in the Northwest, it is also important for a site to have enough ocean depth within several miles of the coast.

An ideal location would:

- capture enough wave energy before the coastal sea floor dissipates it,
- entailminimal cost for mooring cables to the sea floor and for transmission lines to the shore, and
- prevent wave energy conversion technologies from striking the ocean floor during extremely rare severe sea events.

Because the interaction between waves and the sea floor have a large impact on available energy at a given site, sea floor mapping (bathymetric mapping) also is important for assessing energy potential, as well as understanding potential sea floor impacts. Sea mapping will play a critical role in ocean planning for projects beyond wave energy. Examples of bathymetric assessments include multibeam echo sounding, bottom videography and sonar surveys.

The most intense amount of wave activity occurs at roughly between 30 degrees latitude and 60 degrees latitude in both the northern and southern hemispheres. Because this tendency is based on prevailing westerly winds, the western coasts tend to have stronger wave resources than the eastern coast. Areas considered to have the greatest wave energy resource include the western European coast from Scandinavia to the Iberian Peninsula, South Africa, southern Australia, western Canada and the western U.S.

In the U.S., the regions with the best wave resource appear to be Washington, Oregon, Northern California, Hawaii and New England. EPRI estimates that wave energy on U.S. coasts at a 60-meter depth represents 2,100 Terawatt-hours per year (compared to 11,200 of primary energy use in the U.S. today). Data from a Coastal Data Information Program buoy off of Bandon shows a variation of 6 kW/m in the summer to 41 kW/m in the winter. By comparison, EPRI estimates that wave energy in Hawaii ranges from 12 to 22 kW/m. EPRI estimates that Oregon's resource could theoretically supply 20% of the state's power demand.

With funding from BPA, EPRI is currently evaluating forecasting capabilities for wave energy projects.

WAVE TECHNOLOGY BACKGROUND AND EXAMPLES

Wave technologies fall into four broad categories: attenuators, point absorbers, overtopping devices and oscillating water columns.
Due to the lack of demonstrated, technology, it is still not possible to determine which type of technology will be commercially viable for the long term. The devices described below represent those that have undergone testing in ocean conditions, and (except for Wave Dragon) are under active consideration for projects in the U.S. This screen takes out at least a dozen other technologies that are under development in Europe and the U.S.

Due to the industry's infancy, it is too difficult to assess which technologies will “win” as the industry matures. Onsite conditions will test mooring systems for extreme storm events, the ability of systems to withstand corrosion from salt water, and other performance characteristics. Further, data on levelized generation costs, including O&M costs, will require further testing and commercial experience.

O&M costs are particularly important for wave energy. For example, an EPRI study estimated the O&M of at least one device (Ocean Power Delivery's Pelamis device) represents 40% of overall costs, with the capital cost of the device itself a distant second at 28% of overall costs. O&M costs are difficult to assess without real-life experience and represents high uncertainty for the industry.

Experience up to now consists of a handful of tests in ocean environments, plus one commercial project in Portugal. In Europe, the European Marine Energy Centre in Orkney, England, serves as the primary test center for new technologies in the region. In the U.S., no such testing facility exists, though Oregon State is pursuing the development of a National Wave Energy Center at Newport.

Attenuators

Attenuators consist of multiple floating cylinders that lie parallel to predominant wave patterns. Differing wave heights along the length of the attenuator induces horizontal and vertical flexing among the joints connecting the segments. Hydraulic pumps lie between the segments so that the flexing pressurizes a hydraulic fluid that in turn drives a motor connected to a generator. Anchors and cables attach attenuators to the floor. Several attenuators have performed in demonstrations in Ireland, the United Kingdom and Portugal.

Pelamis

Ocean Power Delivery's Pelamis attenuator will perform in the first commercial wave energy plant in the world, a 2.25-MW project off the coast of northern Portugal that will come online in late 2007. It also has tested the device at the European Marine Energy Centre facility at Orkney, England. The Pelamis device at Orkney is 150 meters long (492 feet) and currently provides 750 kW in capacity, with three 250-kW power conversion modules connecting four segments. According to EPRI, testing at Orkney has not revealed fundamental problems with the technology, though it expects improvements in survivability and performance in the next generation. OPD states that the Orkney testing led to changes in the mooring design for future Pelamis projects.

OPD estimates the Pelamis can provide a 25% to 40% capacity factor. Ideal depth is 50 to 70 meters. The device's power curve flattens at a significant wave height of approximately 5.5 meters. OPD estimates a need for a little over 0.1 acres for each MW for a 30-MW project, which would be significantly lower than for other wave power devices.

Point absorbers

Point absorbers resemble buoys and consist of a moving component inside of a relatively fixed cylinder. Waves cause the internal moving component to rise and fall to pressurize hydraulic fluid or create mechanical energy, which then feeds a generator. Point absorbers are connected to the sea floor with cables and anchors. Some versions are fixed to the seabed while others are moored but not rigidly anchored. Demonstrations have occurred in South Africa, Portugal and most recently in Hawaii.

AquaBuoy

Finavera's AquaBuoy entails a hose pump that shortens and elongates with the rise and fall of waves, which results in varied internal volume to pressurize fluid. The fluid runs through a nozzle to a Pelton turbine, coupled with an electrical generator for a closed-cycle device. The AquaBuoy is rated between 80 and 250 kW, with the 250-kW to be the size of choice for their Makah Bay project. The device's depth below the water is 30 meters. It is suited for depths of over 50 meters, with the Makah Bay project to be at 150 meters depth. EPRI estimates that at a 250 kW rating, the AquaBuoy would present a 12% capacity factor. However, AquaBuoy's license application to FERC for the Makah Bay project claims a 18.4% capacity factor for a 28

kW/m average wave resource. Each buoy has a 19.5-foot diameter.

Finavera estimates capital and installation costs for the 1-MW project to be $5.5 million with $50,000/year in O&M for a 30-year life. The Makah Bay project, with four 250-kW buoys, would occupy 6.5 acres (625-by-450 feet), though the footprint of the buoy array itself would be much smaller with 60-foot spacing.

PowerBuoy

Ocean Power Technologies' PowerBuoy is another point absorber device that OPT has tested in 40-kW nameplate configurations at Oahu, Hawaii and Atlantic City, N.J. OPT is developing 150-kW, 250-kW and 500-kW models. The 40-kW device has a 5-meter diameter and a 15-meter depth under water. The Hawaii project is at 30 meters depth, while a 1.25-MW project under construction in Spain would be at 50 meters.

OPT's intends to deploy 250- to 500-kW devices for its Newport project. The permit application for the proposed Newport facility results in a 7.93 acre/MW footprint (0.6-by-3.1 miles with a 100-MW build-out), though OPT has previously referred to a 1.6 acre/MW footprint for a 10-MW project. Lateral spacing for the Newport project would be 330 feet and row spacing would be 660 feet.

For its proposed Newport project, OPT estimates a capacity factor of 35% for a 21.2 kW/m annual average wave energy resource. OPT asserts that the Spanish project under construction would run at almost 30%. Capital and O&M costs are not publicly available from OPT yet.

Overtopping devices

Overtopping technologies consist of a barrier lying as a crescent perpendicular to predominant wave motions. The device concentrates wave heights so that waves heave over the barrier to fill a reservoir. Water runs out of the reservoir through turbines that then generate power. Demonstrations have occurred in Wales and Denmark. Overtopping devices are either fixed to the sea floor or float with mooring to the floor.

Wave Dragon

Danish technology developer Wave Dragon tested a prototype of its overtopping device in Denmark from 2003 to 2005. The device's mooring broke after 18 months resulting in stranding of the device. The testing showed that predicted performance was in line with actual performance, though generation fell above and below predictions during moments of the test. Wave Dragon estimates capacity at 4 MW to 7 MW. The 4-MW device is 260-by-300 meters with a 5,000 to 8,000 cubic meter reservoir size. The device is a combination of reinforced concrete and steel, and uses multiple, parallel Kaplan turbines. The preferred depth is above 25 meters.

Wave Dragon filed for permission to site a device off of the Welsh coast by the summer of 2008 for a five-year test of a 7-MW system. The device will be 0.9 nautical miles off of the coast. Wave Dragon is defining the project area as approximately 3,686 acres (2.4-by-2.4 miles), with the actual footprint occupying 1/30th of the area, or 123 acres, which would translate into approximately 18 acres/MW. Wave Dragon estimates the capacity factor for the 4-MW version to be 35%. A 2005 EPRI study estimated the cost of the 4-MW model as $10-12 million, not including mooring and balance-of-system costs.

Oscillating water columns

Derived from onshore generation technology, OWCs are hollow structures that lie perpendicular to predominant wave movements. Water enters through an opening beneath the surface. Water movement in the chamber in turn pressurizes and depressurizes air trapped above the entering water. Air is expelled up through

a chamber, which then returns as a vacuum forms during wave troughs. As a result, the air flows both ways through a turbine to generate power. OWCs can convert wave energy regardless of the direction of the wave. OWC demonstrations have occurred in Australia and Scotland.

WaveGen

Wavegen manufactures two types of OWCs: one designed for installation on the shore, and another for sites near the shore. Unlike the other devices discussed here, Wavegen's offshore devices are attached solidly to the floor rather than through cables and anchors. Wavegen tested a 500-kW onshore device at Islay, Scotland, beginning in 2000. The device has a concrete envelope and consists of two 250-kW generators driven by Wells turbines. It is located on a natural channel with an opening 2.5-meters below sea level. (Another proposed project on the Faeroe Islands would require a man-made tunnel on the coastline.) The device cost $1.4 million to construct. Information on O&M costs, footprint and capacity factor was not available for this report.

Oceanlinx

Oceanlinx' tested a 500-kW version of its OWC at Port Kembla, Australia, in 2005. The OWC features a funnel-like air outlet that induces a bidirectional flow of air through the turbine chamber. The OWC uses variable-blade air turbines to increase overall efficiency, versus fixed-blade turbines that supposedly can better handle bidirectional air flows. The device is 35-by-15 meters. Oceanlinxhas a preliminary permit to explore a site off of Florence for 10 1-MW devices.

Unlike most other wave energy devices, the Oceanlinxsystem is intended for depths of 50 meters and below, with the Port Kembla project at only 9 meters and 400 meters from shore. The proposed Florence project may be between 0.6 and over 2.5 miles from shore, with a depth of 30 to 150 feet. Like many other wave energy devices, the OWC employs cable mooring, though in this case the cables will attach to the four corners of the device, which is more than for other devices.

For the Florence project, Oceanlinxestimates a 40% capacity factor. The project footprint is not yet clear, though the company applied for a 2.3-by-5.1 mile site with the actual project footprint to be much less. The company did not provide information on capital and O&M costs.

WAVE ENERGY INDUSTRY OVERVIEW

Several firms are active as wave technology and project developers, though only one 2.25-MW project serves as a project in commercial operations. Overall, one observer estimates that there are approximately 25 wave energy technology and/or project developers, though only a handful have test projects installed.

Several well-known firms with engineering and development expertise, including Siemens, PG&E and Chevron, have entered the wave energy sector. But no other major IPP, utility or marine engineering firm has made a major investment in the industry. Given that commercial projects are likely to grow substantially from the very small base over the next several years, the wait-and-see attitude of large firms is understandable as the industry hopes to learn more about device operation and impacts, as well as local attitudes towards large-scale projects.

Technology and/or Project Developers

Finavera. Finavera is a Vancouver, B.C., IPP and technology developer that acquired AquaEnergy in 2006. Finavera has an assortment of planned of wind projects in Canada and Ireland, and its diversified renewable energy project portfolio seems to provide it with the capital and expected revenue stream to withstand potentially lengthy licensing lead-times for wave energy projects in North America. Finavera inherited the AquaBuoy point absorber from AquaEnergy, and intends to deploy it at its U.S. sites. Finavera is listed on the TSX Venture Exchange affiliated with the Toronto Stock Exchange.

In September 2007, Finavera deployed a prototype buoy off of Newport. Oregon Iron Works fabricated the prototype. Finavera signed a systems integration contract with Science Applications International Corporation (SAIC) for final design work.

Finavera has the only potential project in the U.S. that is undergoing a FERC license application — the proposed 1-MW project in Makah Bay, off of Washington's Olympic Peninsula, for which it is seeking a five-year license. Finavera holds a preliminary permit for a site off of Bandon in Coos County, Ore. It also has a preliminary permit for a site off of Fairhaven in Humboldt County, Calif. It is also pursuing wave energy projects in Portugal and South Africa.

Ocean Power Technologies. OPT is a technology and project developer with offices in the U.K. and New Jersey. OPT has several projects planned off of the Oregon coast. The OPT project in Reedsport, Ore., has been awarded a preliminary application and currently is engaged in the Federal licensing process for a 2.1 MW facility. OPT has installed tests of its PowerBuoy point absorber off of Atlantic City, N.J., and Oahu, Hawaii, with the latter project to provide generation for the U.S. Navy. OPT has received funding from New Jersey's Renewable Energy and Economic Development program for the Atlantic City test site and from the U.S. Navy for the Oahu site.

OPT has several European projects under development with Spanish utility Iberdrola as a customer and/or partner. OPT is building a 1.39-MW wave farm off of Spain via a joint venture with Spanish utility Iberdrola, which entered into a contract for the second phase of the project. Iberdrola and French oil company Total also selected OPT to develop a 2- to 5-MW project off of France's Atlantic coast.

OPT is listed on the AIM of the London Stock Exchange and on NASDAQ, where it raised approximately $90 million in its initial U.S. IPO. It also secured a $1.2 million grant from the Scottish Executive to test a new generation of the PowerBuoy device at the European Marine Energy Centre test center. OPT has a development and construction contract with Lockheed Martin Corporation to market cooperatively the PowerBuoy device using Lockheed Martin equipment.

Oceanlinx. Australia-based Oceanlinx, formerly known as Energetech, is a technology and project developer that is pursuing a wave energy project off of Florence. It has secured a preliminary permit for another project off of Rhode Island. Its oscillating water column (OWC) technology is in operation off of the coast of Port Kembla, Victoria, in Australia. Oceanlinx raised 6 million pounds from institutional investors in early 2007. Earlier, it received funding from several U.S. state renewable energy funds — both as venture capital (from the Connecticut Clean Energy Fund) and for its Rhode Island project — and from Australian government agencies.

Chevron California Renewables Inc. The Texas-based company, owned by Chevron, has applied for a preliminary permit for a site off of Mendocino County, Calif., with an initial interest in using Ocean Power Delivery's technology for a project that could range between 2 and 60 MW. (Another Chevron company, Chevron Technology Ventures, LLC, received a preliminary permit for a tidal project in Alaska.)

PG&E. The California investor-owned utility filed two preliminary permit applications for two potential project sites, known as WaveConnect off of Mendocino and Humboldt counties. PG&E intends to be the lead developer of the two sites, which it hopes could provide up to 40 MW each once completed. It intends to issue and RFP for wave energy device suppliers to participate in the projects.

Enersis. Enersis is a Portuguese renewable energy IPP that developed the world's only commercial wave energy site off of the northern coast of Portugal. Enersis' primary experience is in micro-hydro and wind energy development. There is no indication that it is currently seeking projects in the U.S.

Technology Developers and Manufacturers

Ocean Power Delivery. Scotland-based Ocean Power Delivery manufactures the Pelamis attenuator device used in the only commercial wave energy project in the world off of Portugal. NorskHydro's venture capital unit jumpstarted the company by leading an initial round of funding in 2002. Since then OPD has raised almost 28 million pounds from private investors, including Merrill Lynch and GE, which also has provided an equity and term loan. The Scottish Executive government agency has provided Scottish Power with 4 million pounds for a potential 10 million pound project — to be the first in the U.K. — using OPD's devices.

Wavegen. Scotland-based Wavegen manufactures the Limpet OWC that it has tested as an onshore wave energy device at Islay, Scotland, to supply power to the grid since 2000. It is the intended supplier of the generator for Douglas County's proposed project on a jetty in Winchester. It also is developing an OWC for "near-shore" applications at 15-meter depths, which is shallower than typical offshore wave energy devices. It operates a wave test facility in the U.K., which the County may use for testing the viability of the Winchester site. Siemens Voith Hydropower Generation, a joint venture of Siemens and German-based Voith, purchased Wavegen. Wavegen is partnering with npower renewables, a renewables IPP owned by German firm RWE, for project development in the U.K.. It is also building a 300-kW onshore OWC off of the coast of northern Spain.

Columbia Power Technologies. Columbia Power Technologies is a privately held LLC with offices in Virginia and Wilsonville, Ore. It originated as a component of Greenlight Energy, a wind-focused IPP recently purchased by BP, and Oregon-based Peregrine Power. The company is collaborating with OSU to develop and test a 10-kW direct drive buoy (see discussion of OSU's efforts below). It has secured federal funds for the collaboration, including a direct Congressional appropriation and U.S. Small Business Administration Small Business Technology Transfer program funds..

SyncWave. Founded in 2004, SyncWave is a Canadian technology developer pursuing a point absorber technology intended for off-grid applications on the coast or offshore. It has received less than a million Canadian dollars in seed funding and is collaborating with the University of Victoria for device design and testing. It plans to apply for a site south of Tofino, British Columbia, to test the technology. Alberni Engineering, a Canadian manufacturer of marine equipment, is planning to fabricate the first device for testing.

Oregon Iron Works. Oregon Iron Works manufactured Ocean Power Technology's PowerBuoy for OPT's Hawaii project. It is also manufacturing both Finavera's AquaBuoy and OPT's PowerBuoy point absorbers for deployment at sites off of Newport and Reedsport, Ore., respectively. OIW has extensive experience in manufacturing marine equipment. It has expertise in fabrication, machining and outfitting equipment for marine environments. It also has experience in manufacturing equipment employed as replacement parts and relicensing measures for hydropower projects. It is teaming with Scientific Applications International Corporation (SAIC) to design the devices.

Wave Dragon. Denmark-based WaveDragon designs and builds the WaveDragon overtopping device. It tested the device off of Nissen Bredning on the Danish coast for two years and deployed a second version for a one-year test. It has proposed a five-year test off of the Welsh coast. It has also formed a development company with German and Portuguese investors to developer a wave project off of the Portuguese coast. Wave Dragon has received funding from the EU and the Welsh government, with the latter's funding and local project opportunities strong enough to induce the company to move to southern Wales.

PERMITTING

Permitting a wave energy facility will entail working with numerous federal and state agencies. Table 2 outlines agency jurisdiction over key project development issues. Apart from the battle between FERC and the Minerals Management Service (MMS) for lead licensing authority for facilities beyond 3 nautical miles (NM) from the shore, agency jurisdiction is relatively clear compared to the process a developer could face. MMS's intended

process for license application and review is not yet clear, pending the completion of an ongoing programmatic EIS to determine the process. FERC's process is based on its approach to hydroelectric power facility licensing.

Table 2. Agency Jurisdictions Associated with Key Project Development Issues

Jurisdiction	Agency	Authority	Notes
Ocean floor Leasing and Easements	<3 NM: Oregon Department of State Lands	OAR 141-125	Ocean energy facility license for commercial completion. Currently in the middle of a rulemaking on leasing for wave energy projects. There are no special revenue sharing provisions for coastal counties
	>3 NM: Federal Mineral Management Service	Energy Policy Act of 2005 Sec. 388	Currently developing a programmatic Environmental Impact Statement for wave energy facility leasing. 47% of MMS revenues go to the state within 15 NM of project.
Shoreland Leasing and Easements (transmission and potential onshore operations on state lands)	Oregon Parks and Recreation Dept.	OR 736-020	Ocean shore alteration permit for lands located between the extreme low tide line of the Pacific Ocean and statutory vegetation line or the line of established upshore vegetation. Projects may lean toward horizonal directional drilling to connect to inland substations, but still would require agency approval.
Licensing	<3 NM grid-tied: Federal Energy Regulatory Commission	Federal Power Act Sec. 817; National Environmental Policy Act	
	>3 NM grid-tied: FERC or MMS	Federal Power Act Sec. 817 / EPAct 2005 Sec. 388; National Environmental Policy Act	Jurisdiction up for grabs based on vagueness of EPAct-based authority for MMS; MMS involved regardless of outcome due to leasing/easement jurisdiction
Construction	Army Corps of Engineers	Rivers and Harbors Act Sec. 10 – obstructions in navigable waters	
	Oregon Dept. of State Lands	OAR 141-85	Removal-fill permit
Water Quality	Army Corps of Engineers	Clean Water Action Section 404 – dredging, filling, sediment discharge	With guidance from U.S. EPA

	Oregon Dept. of Env. Quality	Clean Water Act Sec. 401 (National Pollution Discharge Elimination System permit)	Likely focus on hydraulic fluids and water temperature changes
		CWA Sec. 401, OAR 340-048	Incorporates conditions into federal license and permit terms.
Biological Impacts	U.S. Fish and Wildlife Service	Endangered Species Act	
		Fish and Wildlife Coordination Act	Along with NMFS, consulted by FERC/MMS
		Marine Mammal Protection Act	Along with NMFS, consulted by FERC/MMS
		Migratory Bird Treaty Act	Bird perching; onshore impacts associated with transmission
	National Marine Fisheries Service (National Oceanic and Atmospheric Administration)	Endangered Species Act	
		Fish and Wildlife Coordination Act	Along with USFWS, consulted by FERC/MMS
		Marine Mammal Protection Act	Along with USFWS, consulted by FERC/MMS
		National Marine Sanctuary Act – impacts on national marine sanctuaries	Sanctuaries exist off of Olympic Peninsula and northern California; none off of Oregon
Alternative Uses	National Marine Fisheries Service (National Oceanic and Atmospheric Administration)	Magnuson-Stevens Act – fishery management	Project must comply with fishery management plan established by Regional Fishery Management Council
	U.S. Coast Guard	33 CFR Part 62 and 66	Avoidance of hazard to navigation
	Oregon Dept. of Land and Coastal Development Consultation with ODFW	Coastal Zone Management Act	Coastal zone certification to ensure compatibility with federally approved state coastal management program (Ocean-Coastal Management Program and Oregon Ocean Resources Management Program)
Cultural	State Historic Preservation Office – Oregon Parks and Recreation Dept.	National Historic Preservation Act Section 106	FERC can enter into an agreement with the Office to build a protection and mitigation plan into the license

FERC Licensing

Preliminary Permits

In addition to applying directly for a license, developers can submit a simple application with no fee to obtain a preliminary permit. The permit essentially reserves a site for up to three years since the developer has top priority in a potential queue. (The permit does not allow the applicant to install a facility.) FERC tends to require the developer to provide frequent reports on permitting progress. FERC provides several key conditions on its preliminary permits:

- First, developers with a permit much file a license application for the same site within 180 to 270 days of issuance of the permit. The requirement limits the potential for entities to "bank" sites, or holding sites without a real intention to develop and with the intention of "reselling" the site to other entities.
- Second, FERC prohibits a transfer of a preliminary permit to another entity. It also bars the creation of a joint development effort between the permit holder and another entity — such a change could trigger a requirement to begin the entire process again. In Oregon, the prohibition would require those municipal and county entities with permits to develop sites as the lead entity with significant restrictions on commercial relationships with other developers.
- Third, even if FERC issues a permit for a site, another developer can submit a competing preliminary permit application for the site. However, the original applicant has an advantage since the second applicant must show its proposal is "better adapted" for the stated goal. And even if it is, FERC allows the original applicant can resubmit its application in response. Such a "second-chance" system provides an incumbent advantage for the first applicant who holds the permit. Consequently, developers in the U.S. have rushed to "bank" preliminary permits for many sites, with one law firm alone submitted 12 applications to FERC from late 2005 to early 2006.

FERC is mindful of the banking issue. For example, in its preliminary permit for the AquaEnergy project southwest of Bandon, FERC emphasizes its "strict scrutiny" approach by requiring AquaEnergy to establish a set of deadlines for preparing their license application to show progress and avoid virtual squatting on the site. If FERC determines that the applicant is not making sufficient progress on licensing, it can cancel the permit.

FERC prohibits a transfer of a preliminary permit to another entity. It also bars the creation of a joint development effort between the permit holder and another entity — such a change could trigger a requirement to begin the entire process again.

FERC can offer certain experimental projects an exemption from typical licensing requirements. The "Verdant exception", named after a tidal energy project in New York City's East River that first obtained the exemption, is contingent on several project characteristics:

- Experimental technology with uncertain performance characteristics
- Short operational duration (up to 18 months) to gather data for a future license application
- No delivery of power to the grid, thereby avoiding interstate commerce considerations

The first planned phase of a project in Reedsport may fall under the Verdant exception to prove the viability of wave energy technology off of the Oregon coast.

As of July 2007, FERC issued 43 preliminary permits to wave and tidal projects, with five in Oregon. Among the other states with sites covered by preliminary permits, Alaska has 9, Florida has eight, Washington has eight (seven of which are for tidal projects with Snohomish PUD as the applicant), New York has five (all tidal), Maine has four (with two sites shared with New Hampshire), and California and Massachusetts have one each (with California's site in San Francisco Bay).

As of July 2007, FERC received 15 additional applications for preliminary permits, with three in Oregon.

Among the other states with sites that are the subject of permit applications, Maine has six, California has four (two of which are sites off of Humboldt and Mendocino Counties with PG&E as the applicant), and Massachusetts has two.

Licensing Processes

The greatest concern among developers is the amount of time needed to obtain a license for a project. Absent a process specific to emerging wave and tidal energy projects, FERC is looking to the traditional hydroelectric project licensing process, which tends to take three to five years of winding through a convoluted process that is more suited to stable, rate-based utilities that can take the risk of not succeeding in licensing a project. Alternatively, wave and tidal energy developers, are more like commercial startups with a limited capability to absorb high permitting costs and licensing failure.

The licensing process can follow three different paths: integrated, traditional and alternative licensing processes. The focus of each process is to produce an acceptable Environmental Assessment or Environmental Impact Statement per NEPA while incorporating other relevant statutory requirements.

FERC developed each process with hydropower projects in mind. Some observers believe that FERC's staff appears not to be amenable to adjusting each process in order to take into account different characteristics of wave and tidal energy projects.

First, the industry consists mainly of small, startup firms with the funds to withstand licensing that can take five years to complete. This is different from the utility-dominated hydropower industry. Second, wave and tidal projects on average will be smaller than hydropower projects, raising the potential of high licensing costs per unit of energy generated. Finally, the technology and/or its application is relatively novel, spurring interest among developers and others in quickly installing pilot projects to better understand impacts for future licensing efforts.

Integrated licensing process

Created by FERC in 2003, the integrated licensing process (ILP) is the default licensing process for hydroelectric facilities. FERC intended the ILP to front load stakeholder consultation to avoid time-consuming and expensive studies after the applicant files for a license. The ILP has several key features and steps:

- Extensive consultations by the applicant with state agencies, federal agencies, tribes and other stakeholders early in the process, and before the license application, to avoid extensive studies and challenges later in the process.
- Project study plan scoping by FERC staff for NEPA compliance early in the process to avoid additional studies later. Stakeholders meet frequently to resolve any differences between the applicant and stakeholders, and among stakeholders.
- Applicant filing of a draft study plan with detailed schedule with firm deadlines for all licensing steps, including studies and consultation. Stakeholders review the plan and FERC approves it with modifications if desired.
- A formal dispute resolution process to be initiated only by state and federal agencies and tribes with mandatory conditioning authority under the Federal Power Act and the Clean Water Act, with other stakeholders having to petition FERC for additional study requests.
- A three-member study advisory panel to consider "notices of dispute" filed by agencies that challenge the study plan. The decisions of the panel are binding, unless in other licensing processes.

After completing studies, the applicant files a draft application with a subsequent comment period for stakeholders. After the comment period, the applicant files a final application. FERC considers subsequent recommendations and conditions proposed by agencies before issuing a final NEPA document. FERC then

issues or denies the license, with an issued license including state and federal license conditions

Traditional licensing process

The traditional licensing process (TLP) was the default process for hydropower licensing until 2005, when the integrated licensing process became the default process. The TLP does not focus on pre-application consultation between the applicant, agencies and other stakeholders (although FERC did modify the TLP to require some pre-application consultation between the applicant and other stakeholders). Compared to the ILP, the TLP sets out a sequential process of study design, study completion, stakeholder requests for additional studies, and FERC scoping for NEPA compliance. FERC staff rarely participates in the pre-application consultation.

FERC staff has said that they are more likely to approve the TLP process for a project if it appears that the application will not have a lot of controversy, with the potential for relatively quick implementation. Controversy can translate into requests for additional studies, to which the TLP is more susceptible compared to the ILP since it does not include as much pre-application consultation to produce a set of studies with relatively strong stakeholder approval. Experts also see the TLP as beneficial if there is enough information to evaluate a project application.

The applicant consults with agencies to identify studies to complete for the license application. The applicant completes the studies and submits a draft application. Agencies comment on the application. An informal, nonbinding dispute resolution process can ensue to resolve differences on further studies and/or project mitigation steps.

After an applicant files for a license, agencies and other stakeholders can make comments and recommendations. In contrast to the ILP, they can also request additional studies. Also in contrast to the ALP, FERC staff then begins to identify key study issues, whereas in the ILP such scoping occurs prior to the license application. FERC staff then prepares a NEPA document with analysis and proposed project conditions, which FERC commissioners then review to decide whether to issue or deny a license.

In July 2007, Ocean Power Technologies filed a notice to pursue the traditional licensing process for its 2.25-MW Reedsport project. Opting for the TLP rather than the default ILP avoids extensive consultation early in the process when the necessary information on operations and impacts is not yet known. Rather, OPT and the Oregon Solutions facilitators saw the TLP as a process that offers more opportunity to gather information on potential project impacts prior to interacting formally with agencies and stakeholders.

Other developers in the U.S. have sought the ILP to work through issues early on while gathering key data. For example, Ocean Renewable Power Company plans to use the ILP for its projects in Cobscook Bay and near the St. Croix River in Maine. ORPC plans to run a six-week pilot for its tidal power "cross-flow" turbines, with the pilot producing performance data that will feed into the ILP.

Since the OPT Reedsport project also features a pilot phase, the difference in strategies likely reflect different judgments by the developers and other parties. A couple of years of experience should provide the industry with better information on how the different licensing processes compare for siting wave and tidal projects efficiently.

Alternative licensing process.

FERC intends alternative licensing process to be highly collaborative, with a requirement that applicants obtain formal support from agencies to pursue the ALP. The applicant works closely with stakeholders to develop the preliminary draft NEPA document, with FERC overseeing the process through the establishment of a formal communications protocol among the parties. A firm set of deadlines, however, is less likely to exist in the ALP

compared to the ILP, leaving the process susceptible to lengthy deliberations in the pre-application phase.

The ALP has several other unique characteristics:

- A voluntary Dispute Resolution Service to address disagreements, though the opinions are not binding.
- Ideally the pre-application collaboration leads to a settlement agreement between the applicant and stakeholders, including conditions imposed by state and federal agencies.
- The formal license application includes a draft NEPA document, rather than just a set of environmental studies. FERC reviews the document and determines whether to issue or deny the permit.

Energetech (now known as Oceanlinks) opted for the ALP for licensing its attenuator project off of Port Judith, Rhode Island, at FERC's suggestion.

Some observers note that the ALP tends to be more costly than the other processes. But the ALP might hold favor in the future in cases where agencies and tribes with mandatory conditioning authority are particularly contentious over project licensing.

FERC's Recent Proposal for Wave Energy Pilot Projects

In July 2007, FERC announced that it would hold a technical conference in October 2007 in Portland, Ore., to examine the merits and mechanics of a streamlined licensing process for pilot projects. FERC mentioned the possibility of a six-month licensing process for projects that are (1) 5 MW or smaller, (2) removable or able to shut down on short notice, (3) located in waters without sensitive designations, and (4) useful for testing new technologies or determining appropriate sites. The permit holder would have the option to apply for a 30- to 50-year license after the pilot-permit term ends.

If FERC adopts such a process, it can lead to quick installation of small wave energy projects in the Northwest. However, another consideration is the time it will take other federal and state agencies, such as the Army Corps of Engineers and the Department of State Lands, to process applications. If other agencies do not accelerate review, then the FERC initiative may not effectively speed up licensing of small projects.

MMS Leasing and Licensing Efforts

As required by the 2005 Energy Policy Act (EPAct 2005), the MMS has the lead leasing, easement, and rights-of-way authority for renewable energy projects located on the outer continental shelf (OCS), which is typically between 3 and 200 nautical miles (NM) offshore. (The shore in this case is equal to the mean low water line along the coast as indicated on U.S. nautical charts. MMS's OCS authority does not cover national wildlife refuges, national parks, national monuments and national marine reserves, although this issue does not affect the Oregon coast.) MMS is trying to assert its jurisdiction for licensing projects on the OCS, though FERC disagrees.

The MMS is moving forward to lay out a leasing process for renewable energy projects, including project plan reviews, lease issuance and decommissioning. MMS's program would be covered by NEPA as a major federal action with the potential for significant environmental changes. Consequently, MMS has begun a programmatic EIS to identify environmental and cultural impacts of a future program. It hopes that the EIS will facilitate site-specific preparation of NEPA documents. It intends to issue a final EIS in 2008. The EIS's development does not preclude project approval, since MMS can still conduct site-specific project reviews.

While MMS's leasing authority is clear, it is less clear that they have licensing authority over projects. MMS is asserted such authority, while FERC maintains that it has licensing authority on the outer continental shelf. EPAct 2005 does not allow MMS authority to supercede existing authority among other agencies, including possibly FERC. No renewable energy project has yet exposed the issue to force administrative or judicial resolution of the potential conflict between FERC and MMS for licensing projects.

STATUS OF PERMITTING OREGON WAVE POWER PROJECTS

Oregon Projects with Preliminary Permits

Finavera's Coos County wave power project. AquaEnergy, owned by Ireland-based IPP Finavera, received a FERC preliminary permit for a site southwest of Bandon off of the Coos County shore. The project could ultimately consist of 200 to 300 point absorber buoys that could have a nameplate capacity of 200 kW to 1 MW each. Finavera envisions a possible maximum of 100 MW built in phases based on the final license conditions. The first phase would be 2 MW. AquaEnergy originally proposed a site that went beyond the 3-NM boundary into the Outer Continental Shelf, but revised the location to be fully within FERC's jurisdiction and above the sea floor where the state has leasing and easement jurisdiction. FERC requires Finavera to issue a Notice of Intent (NOI) to file a license application, as well as a pre-application document (PAD), within a year of the April 26, 2007, issuance of the preliminary permit. Finavera intends to begin the licensing process in 2009 or 2010. EPRI estimates a 6-41 kW/m potential based on buoy data. Testing, survey and study costs are estimated at $1.5 million.

Oregon Wave Energy Partners' Coos Bay wave energy project. OPT is pursuing a site 25 miles south of its Reedsport site, 2.5 miles offshore and northwest of Coos Bay. It intends to develop a 100-MW project consisting of 200 to 400 point absorber buoys. OPT would configure the buoys in three to six rows parallel to the coast. Each array would consist of 35 to 150 devices. The company proposed a study site within a one-by-five-mile area, though the project itself could occupy a 0.4-by-3.1 mile area whose location will depend on further bathymetric studies. OPT is looking to connect into Central Lincoln PUD's grid. It aims to file an NOI and PAD with FERC by March 2008, using its process for the Reedsport project to shape its license process preference and strategy for the Coos Bay site. Study costs are $500,000.

Ocean Power Technology's Reedsport Wave Park project. FERC issued a preliminary permit to OPT for a 50-MW project off of Reedsport. The project could ultimately consist of 200 point absorber devices in four rows parallel to the coast and rated at 250 kW each. The study site is one-by-five miles, though the project itself could occupy a 0.4-by-3.1 mile area whose location will depend on further bathymetric studies. In July 2007 OPT filed an NOI and PAD to initiate the licensing process. It has requested the traditional licensing process. It plans to install a test buoy on the site next year, though the buoy will not deliver power to the grid. The second phase would consist of 14 150-kW buoys for a total of 2.1 MW. Study costs are $500,000.

PNGC Power has invested $500,000 for the fabrication of a 150-kW test device. Both Central Lincoln PUD and PNGC have offered a three-year PPA with the 2.1 MW phase to incentivize its development. PNGC Power also has rights to buy into or purchase the power from the full 50-MW project.

Oregon Tidal Energy Company's Columbia River tidal power project. The Washington, D.C.-based OTEC, a subsidiary of Oceana Energy in Mass., received a FERC permit in March 2007 for seven tidal energy sites from the mouth of the Columbia River to 15 miles upstream. Four sites are on the Oregon side of the river along Clatsop County, while the remaining three sites are on the Washington side along Wahkiakum County. Depths for the sites range from 25 to 75 feet. OTEC is hoping for 50 to 150 tidal instream energy conversion devices rated at 500 kW to 2 MW each. The project would arrive in three phases, beginning with a temporary test installation 20 months after receiving the preliminary permit, a second expansion phase approximately two years after the preliminary permit, and a third expansion phase four years after the preliminary permit. In a recent report, Oceana pushed back the hoped-for date of test device installation to late 2009 or early 2010, with filing of the NOI and PAD for licensing to occur in early 2008. Study costs between $1-$4 million.

Douglas County's Winchester project. Douglas County originally intended to obtain a preliminary permit to limit other developers' activity off of the coast until the county had a better understanding of impacts. But

FERC issued a preliminary permit to a specific project area while the county explores the possibility of supporting a project. The County is now hoping to install U.K.-based WaveGen's heave device by retrofitting a jetty owned by the Army Corps of Engineers at Winchester, by the mouth of the Umpqua River. The project could be 1 to 3 MW. The County will conduct wave energy, bathymetric, preliminary device and grid impacts studies this year. It also plans to test the Wavegen device at a wave tank. The Corps submitted a letter to FERC emphasizing concerns about potential impacts to the jetty's structure.

Oregon Projects With Pending Permits

Ocean Power Technologies' Newport wave energy project. OPT filed for a preliminary permit for a site south of Newport and north of Waldport. The project would be between three to six miles from shore, prompting the MMS to file a protest over FERC's jurisdiction over the project. The potential 100-MW project could consist of 200-400 point absorbers that could range from 250-500 kW, and in three to six rows parallel to the shore, to total up to 100 MW. OPT is requesting a permit for a 3.5-by-5-mile area in order to conduct sea floor mapping to determine the optimal project site, which would be smaller than the site covered in the permit. OPT would aim to submit a license application in 2008 or 2009.

Lincoln County's application for a wave energy project. Like Douglas County, Lincoln County contemplated obtaining a permit for their entire coast to secure nine potential locations identified by the county and Central Lincoln PUD for potential wave energy projects totaling between 20 and 180 MW.

Some observers believe that the county was attempting to preclude site banking by other developers, and to ensure the county's role in determining project locations. Comments filed by PGE expressed concern that other potential projects in the area would be shut out if FERC granted the County a permit based on its originally application. FERC demanded that the county restrict its application to a more specific project site.

Lincoln County's effort is now focused on siting a test location for two-point absorber buoys, each owned by Finavera and Oregon State University, with a third buoy to provide monitoring data. The County has the support of a fishermen group — Fishermen Involved in Natural Energy (FINE) -- that the County entrusted to represent local fishing community interests. Because of the test nature of the project, the County requested a Verdant exemption in April 2007 for the project to expedite licensing and installation.

Oceanlinx' Florence wave energy project. Oceanlinx, has proposed a 10-MW project with 10 oscillating water column devices with a 3.4-mile long, 11-kV transmission line. The project would be between 0.6 and 2.9 miles from shore (i.e., just within FERC's undisputed jurisdiction versus the MMS). The company has proposed that the permit cover an area 2.3-by-5.1 miles. Oceanlinx intends to submit a license application in 2010.

STAKEHOLDERS INVOLVED IN OREGON PROJECT PERMITTING

Wave energy projects were not a high-profile issue on the Oregon coast until recently. A slew of FERC permit applications have raised awareness of the project potential in the area. Consequently, a current snapshot of stakeholders participating in siting processes probably does not capture the full range of stakeholders even in the near future as processes progress and onsite device testing begins. Nevertheless, the following list already includes a range of economic and environmental interests that can wave energy projects can affect. Note that the list does not include state agencies with formal roles in project licensing (as described in Table 1), nor does it include county and municipal governments actively engaged in developing wave energy projects.

Confederated Tribes of the Coos, Lower Umpqua and Siuslaw Indians. The confederation is a signatory to the Oregon Solutions Declaration of Cooperation for the OPT Reedsport project.

Fishermen for Natural Energy (FINE). FINE is the creation of a group of fishermen that joined to express their views on wave energy project siting in Lincoln County. This group participated significantly in assisting

with site location for Finavera and OSU prototype testing in 2007. The County then tapped FINE in their ordinance to represent the local fishing community's views for wave energy permitting. Tillamook County is supposedly considering a similar approach for siting on waters off of their county.

Oregon Shores. Oregon Shores is an environmental nonprofit that has advocated testing wave energy facilities to understand environmental impacts before launching large-scale wave energy projects. It signed the Oregon Solutions Declaration of Cooperation for the OPT Reedsport project.

Oregon Coastal Zone Management Association. The Association is a 501(c)3 nonprofit consisting of coastal counties, cities, ports and tribes. OCZMA seeks consensus among its members and takes positions when it sees fit on coastal issues. It is actively engaged in wave energy project permitting in Oregon. Its position is one of watchful interest in ensuring that projects do not impact other coastal economic activity while supporting coastal counties' efforts to develop projects for economic development. Its executive director is a member of the Oregon Wave Energy Trust. It has signed the Oregon Solutions Declaration of Cooperation for the OPT Reedsport project.

Oregon Department of Energy. ODOE has supported the exploration of wave energy development and is a signatory to the Oregon Solutions Declaration of Cooperation for the OPT Reedsport project.

Oregon Dungeness Crab Commission. The Commission expressed opposition to all projects within 3 NM of the shore, due to potential impacts on crabbing activities on sandy ocean floors that developers tend to prefer for anchoring and mooring systems.

Oregon Fishermen's Cable Committee. OFCC represents trawlers and originally focusing on undersea fiberoptic cable siting issues. It is involved in wave energy project siting and signed the Oregon Solutions Declaration of Cooperation for the OPT Reedsport project.

Oregon Sea Grant. The program is a part of NOAA and housed at Oregon State University. It is a network of scientists, educators and community outreach staff primarily employed at the university. Half of its $5 million in annual funds goes toward scientific research. It is actively involved in wave energy development, including its efforts to work with local fishing communities who might be affected by wave energy projects.

Oregonshores. Oregonshores is an environmental nonprofit that has advocated for testing wave energy facilities to understand environmental impacts before launching large-scale wave energy projects. It signed the Oregon Solutions Declaration of Cooperation for the OPT Reedsport project.

Surfrider Foundation. This national environmental nonprofit is focusing on surfing and environmental impacts of wave energy projects. It appears mindful of the importance of renewable energy and is interested in better understanding project impacts. It has signed the Oregon Solutions Declaration of Cooperation for the OPT Reedsport project.

INITIATIVES IN OREGON TO DEVELOP WAVE ENERGY

Oregon has been the most active state in the U.S. in wave energy research, development and demonstration (RD&D).

Oregon Solutions

Oregon Solutions is facilitating permitting efforts for the OPT Reedsport project. Oregon Solutions is a program of the National Policy Consensus Center and originated in former Governor John Kitzhaber's administration. The group is devoted to fostering consensus-based decisions related to environmentally friendly projects and programs in the state.

For the Reedsport project, Oregon Solutions has brokered a Declaration of Cooperation among numerous local and state agencies, tribes, local economic interest groups, utilities and environmental groups. The Declaration commits signatories to participate in the Oregon Solutions process until a FERC licensing determination occurs. A subset of signatories further agreed to timely participation so that licensing deadlines are met, while a smaller subset agreed to specific deadlines for numerous licensing requirements.

Oregon Wave Energy Trust

The Oregon Wave Energy Trust (OWET) is a 501(c)(6) nonprofit formed in January of 2007 to address statewide issues affecting wave energy development. Its Board consists of representatives of wave energy developers and utilities among others. OWET received $4.2 million in funding from the state legislature after Oregon Innovation Council vetted the Trust's funding proposal. The funding is a part of the Council's implementation of the Oregon Wave Energy Initiative, a broader effort to nurture an emerging industry in the state that offers the potential for economic development and job creation. The Oregon Economic and Community Development Department (OECDD) will disburse the funds to OWET.

OWET is considering its plan for investing the funds. Among the ideas under consideration are a statewide environmental, technical research and development projects, economic and cultural impacts of new projects, and identifying ways to streamline the regulatory process. It also seeks to provide incentives to projects such as matching funds for permitting and developing ideas for production incentives, though some members recognize the limited ability of OWET to provide incentives to specific projects due to limited funds.

Oregon State University

OSU is pursuing several efforts to further wave energy RD&D in the state:

- OSU's Motor Systems Resource Facility is designing a direct-drive, wave energy device based on magnetic fields and power electronics. It is partnering with Columbia Power Technologies in Virginia for technology licensing and future deployment. Funding for the effort has come from U.S. DOE, the National Science Foundation, NOAA and the Grainger Foundation.
- OSU is promoting a testing facility at Newport, with the Hatfield Marine Science Center serving as the potential land-based facility. The ambition is to establish the test site as the National Wave Energy Research and Demonstration Center.
- OSU operates the Hinsdale Wave Research Lab, a wave tank facility that can simulate ocean conditions for wave energy device testing and impacts research.

CONSIDERATIONS FOR ETO

The technology is unproven in commercial, onsite applications, and there is no sense of what technologies will "win" or what the real project costs are.

The wave energy industry has yet to install a commercial project, so onsite performance characteristics are still an unknown with short-term demonstrations the only record of note. Key issues cited by experts as requiring more evaluation include mooring for extreme events, salt water corrosion, power control systems and construction methods. The durability of the generation technology over more than 10 to 15 years is also uncertain, making the cost of meeting the terms of a 20-year-plus power purchase agreement uncertain. Perhaps the biggest mystery is long-term O&M costs given the offshore location of devices.

Without enough operating experience, no expert can predict which technology or set of technologies will prove to be the most reliable and cost-effective. Certain developers have access to more capital and financing than others, but the state of in the industry right now is one of anticipation. For those interested in supporting

specific firms and technologies today, there is little to minimize technology risk.

Opportunities to support small pilot projects may arise more quickly than expected — within the next two years.

FERC's recent proposal to streamline licensing for projects at 5 MW or less offers hope that wave energy projects will materialize more quickly than previously expected. For the proposal to succeed, other key federal and state agencies also will have to commit to expeditious review and decision making. If the relevant agencies effectively coordinate their efforts, the first generation of operational wave energy projects in the U.S. may emerge within a couple of years. This possibility offers opportunity to give near-term incentives to projects.

Federal policy needs to mature to make wave energy competitive with other renewables.

Wave energy technology appears to pose higher capital cost and O&M costs than the most prominent renewable energy technology today, onshore wind energy. The lack of experience significantly raises financial costs due to perceived risk associated with permitting and technology uncertainty, unproven company performance, and the lack of engineering, procurement and construction (EPC) guarantees.

While the above issues are important to overcome, the availability of federal incentives that other renewable energy technologies receive would narrow the cost gap between wave energy and other renewables. Unfortunately, the federal production tax credit (PTC), currently set at $19/MWh by the IRS, does not apply to wave energy. Without a PTC, wave energy stands little chance of making a significant contribution to Oregon's renewable energy mix. It also raises the above-market premium that the Energy Trust might have to contribute to make projects happen.

Federal policy does not just fall short on incentives. The lack of federal RD&D funds places an inordinate onus on the wave energy industry, states and overseas governments to advance the technology. The current hope from the industry is $6 to $8 million in federal RD&D funds, which at least initiates the establishment of programs to support the industry.

Finally, wave energy is not a familiar technology to permitting agencies such as FERC, MMS, the Army Corps of Engineers and state agencies. These agencies have begun earnest efforts to understand wave energy, but the likelihood is that it will take several years before the wave energy industry can engage with regulators who have a working knowledge of the industry. In the meantime, education will take up a lot of industry resources, and uncertainty in agency behavior will predominate.

Feed-in tariffs and grants are driving commercial projects in Europe, while renewable mandates serve as an indirect incentive for power purchasers to explore wave energy.

Upfront incentives and generous tariffs are driving new commercial wave energy projects in Europe. Portugal offers a tariff equal to approximately 32 cents/kWh over a 15-year period for the first 20 MW of wave energy projects, with a possible increase to 50 MW. The U.K.'s Department of Trade and Industry runs an $85 million Marine Deployment Fund that began in early 2006, and can cover up to 25% of a project's costs. The Scottish Executive is making capital grants to projects.

Interestingly, the U.K.'s renewables obligation — its RPS — is not a direct driver for a number of recent proposals for commercial projects. Rather, the direct incentives above are driving early development, with the obligation serving as an indirect inducement by utilities such as ScottishPower to nurture extraction of strong local resources.

Given wave energy's competition for RPS-driven markets in the U.S., it is unlikely that state RPSs alone will do much for wave energy in the near term. Direct incentives are required. Plus, since the federal government does

not yet provide incentives for wave energy, other institutions will have to make up the difference. They will have to compete with Europe for small wave energy firms' limited resources. They will have to offer incentives that provide good returns, and which are devoid of policy risk and reward developers for the substantial development risk they are undertaking today.

While Oregon is the current focus of wave energy development on the West Coast, the California power market will be a strong attraction for developers.

While Oregon has a strong wave energy resource, wave energy developers also can look to California, Washington and British Columbia for project opportunities. Fortunately for Oregon, both Washington and British Columbia have relatively sparse transmission networks near the coast, limiting the power marketing opportunities for wave energy developers. However, California has transmission near the coast. Just as important, it also has relatively high power prices, an aggressive renewable portfolio standard, numerous incentive programs related to the RPS and other programs such as the Public Interest Energy Research program, and large power demand.

Consequently, Oregon has to be mindful of the possibility that the bulk of the industry's development efforts could move to the south, particularly if one or more projects in the state succeed in licensing. The industry's early stage of exploration may make it more sensitive to small differences in factors such as permitting ease and available incentives. California's inherent advantages also open up the possibility of Oregon-based projects to market their power south.

For Oregon to ensure wave energy projects off of its coast, the California factor should encourage stakeholders and regulators to avoid being too cautious in establishing pilot projects that can quickly contribute to collective learning about project impacts and benefits. For incentives, Oregon cannot compete with California on the sheer amount of money available. However, the ability to minimize transaction costs for small developers to secure funds could help.

Oregon is nurturing stakeholder collaboration on siting, but the ultimate ease of siting for large-scale projects is unknown.

Currently Oregon stakeholders are focused on small-scale pilot projects off of the coast. The mood of coast-oriented interest groups is a mix of wariness over potential impacts, as well as interest in potential economic development benefits. However, once the focus moves on to large-scale, “build-out” projects, the results of the pilot projects likely will generate concern about aesthetics, as well as questions about biological, physical and socioeconomic impacts.

Efforts such as those of the Oregon Wave Energy Trust seek to identify and address potential siting controversies now by identify “no-go” areas that would arouse public concern over potential impacts.

Nevertheless, any institution interested in wave energy will have to recognize that current discussions over wave energy siting may actually be more amicable than the next phase of discussions on large projects. Consequently, the ability to weather controversy will be essential; particularly since the wave energy industry would need to know that incentive programs will be there for them if they make it through licensing.

Several experts mentioned funding for siting as important. There will be a tension between such support and the guarantee of future power production. The lower risk of siting pilot-scale projects makes support for siting such projects less risky than supporting siting for larger projects.

Interest from Oregon's investor-owned utilities in wave energy is not yet clear, though their interest is important particularly for projects above 10 MW.

The key utilities in Oregon that are expressing support, investing funds and exploring grid-related issues are public utilities such as Central Lincoln PUD, the PNGC consortium and BPA. PGE has expressed some interest, and a PGE official is one the board of OWET. Less clear is PacifiCorp's interest in wave energy. PacifiCorp's interest is important — the utility serves most major communities on the coast, including Coos Bay, Lincoln City and Astoria.

Wave energy projects underneath 10 MW could decide to sell power under PURPA at a published rate. But all developers active on the Oregon coast aspire to projects well above 10 MW. Absent sales under the PURPA published rate, developers will need to enter into intricate negotiations with utilities to make their projects work. If ETO is to provide incentives to new wave energy projects, then PacifiCorp's absence from wave energy initiatives can pose a problem, particularly for projects above 10 MW.

Near-term benefits to ratepayers are small, but the potential of local generation and local industry development can provide meaningful benefits to the state in the long term.

Numerous Oregon institutions have succeeding in initiating and coordinating efforts to support a nascent wave energy industry in Oregon. Attracting the industry to the state is easier now than it will likely be as it grows, attracts attention, and nurtures competition among states and nations to grab the economic benefits of manufacturing, services and generation.

Oregon's ratepayers will not receive a lot of energy benefits from wave energy projects in at least the next five years. But the U.S. West Coast may see over 10 projects materialize in several years. Oregon's position as a center for wave energy device manufacturing, design and testing means that it could become the center of a growing industry in North America. Competition for such activities may come from British Columbia, Washington or California, making it imperative that Oregon maintain and expand its efforts to nurture the industry.

GEOTHERMAL ENERGY

INTRODUCTION

The geothermal energy power industry is witnessing a second rush of project development and enthusiasm from the financial sector following an initial growth spurt in the 1980s. The ability to provide baseload power using familiar generation technology and long-standing drilling techniques makes the industry a safer bet for investor's dollars compared to solar thermal electric and wave energy. While development continues in California and Nevada, fueled by RPSs and strong resources, Oregon continues to wait for the first large-scale power generation project to materialize. The state has good geothermal resources, both for large-scale and small-scale projects. The latter category may be of particular interest to the state due to opportunities in the south, and the recent development of generation technology that may make small projects more viable than before.

In addition to briefly discussing technology, resource, and relevant firms, this section summarizes current project efforts in Oregon as well as permitting issues with a focus on federal lands.

TECHNOLOGY

Geothermal energy is based on high subterranean temperatures capable of heating water and/or a heat-carrying fluid. Geothermal energy can serve various uses, including direct uses such as hot water and heating for buildings. This section focuses on geothermal energy for power generation, while recognizing that other uses are viable and can co-exist with power generation, even from the same reservoir.

Power generation from geothermal energy features two main types of generation technologies which correspond with different categories of heat availability:

- Flash steam technology is based on availability of hot water from roughly 300°F (149°C) and higher. When pumps bring the hot water from high-pressure subterranean reservoirs, water pressure drops and a portion of the water becomes vapor. The vapor can run a turbine which is coupled with a generator to produce power. Vapor either exits the plant and into the atmosphere with trace emissions of sulfur, carbon dioxide and nitric acid, or condenses and re-enters the underground reservoir.
- Binary technology is appropriate for lower water temperatures, ranging roughly from 100°F (38°C) to 300°F (149°C), with temperatures below that range possible in higher altitudes. Binary technology relies on a transfer of heat from the water to a heat-carrying fluid within a heat exchanger. The fluid tends to have a low boiling point. The water and the other fluid do not come into contact. The fluid turns into vapor and runs a turbine, which connects to a generator to produce power. Both the vapor and the heat-carrying fluid condense and run through the plant again, resulting in a closed-loop system with no emissions.

Capital costs for either type of plant are a function of several factors, including:

- The required depth of the well (and hence the cost of well drilling) and associated pumping costs.
- Number of wells required.
- Choice of air cooling or water cooling to condense the water and the heat-transfer fluid in binary plants. Air cooling adds capital costs and results in parasitic load loss to reduce efficiency. Water cooling requires water rights for a reliable supply of cold water.
- Balance of plant costs, including transformers and transmission line upgrades.

A study of California and Nevada geothermal power generation potential estimates capital costs (including

balance-of-plant) to average $3,100/kW, with a range of $1,000/kW for small expansions to existing projects and a very high end of $6,000/kW for deep and low-temperature resources. It found $2,400/kW to be competitive with other renewables and characteristic of substantial new generation opportunities in the two states. A study for the Warm Springs tribe roughly estimates $3,600/kW (including $1,800/kW for balance-of-plant). The latter study assumes a range of O&M costs between 2 and 2.5 cents/kWh. A Western Governors Association (WGA) study assumes an O&M cost of 2.2 cents/kWh.

Well drilling is a significant component of a project's costs, representing up to 50% of project costs based on depth, rock properties, and the presence of corrosive fluids underground. Wells are required to access hot water as well as to inject fluids underground. The depth and diameter of a well can vary, with depths of up to 10,000 feet for large potential projects. Initial test wells are required to determine whether a site is viable. This drilling step in particular is risky for entities that do not have the ability to take advantage of the federal deduction for drilling and development and yield a poor resource.

RESOURCE

Oregon contains numerous pockets of concentrated geothermal energy resources. The state's resource falls into three broad categories: (1) those associated with areas of historical and current volcanic activity, primarily along the Cascade Range, (2) those associated with the "basin and range" feature on southern and southeast Oregon, and (3) those associated with the Snake River basin that stretches into far eastern Oregon from Idaho.

Mere availability of high subterranean temperatures is not enough for a viable geothermal power plant. Other key factors are sufficient water availability in the geothermal reservoir to carry the heat usefully to the surface, and cold water availability for condensation. Statewide mapping of well temperatures alone therefore will not predict geothermal plant viability. Rather, it can serve as a useful screen for sites for further exploration and development.

Mapping in 2003 by the Idaho National Laboratory (INEEL) shows wells above 50°C in several discernable clusters: southern Klamath County, central and southern Lake County, southeast Harney County, northern Harney County east of Burns, northeast Malheur County surrounding Ontario, southern Deschutes County at Newberry Crater, and intermittently in the Cascade Range from Santiam Pass up to Mount Hood. In 1978, the U.S. Geological Survey designed 7 areas in Oregon as "known geothermal resource areas" (KGRAs) with sufficient resource for power generation and direct uses, and open to competitive leasing. The areas correspond to the locations with high-temperature wells on INEEL's 2003 map.

Oregon features enough geothermal resource to support multiple power plants, both flash steam and binary. The Western Governors Association estimates that Oregon could house 380 MW of geothermal power capacity with a levelized cost of 8 cents/kWh and another 1,250 MW with a levelized cost of 20 cents/kWh. However, Oregon is also a state of unmet expectations for geothermal power development, with no generation currently on line.

PAST EXPLORATION EFFORTS

Exploration in Oregon began in earnest in the 1970s and 1980s, when oil and gas companies such as Anadarko and Union Oil combed the West for high temperature geothermal reservoirs capable of supporting large-scale power plants akin to the 2,000-MW Geysers complex in northern California.

- In Oregon, Newberry Crater in lower Deschutes County attracted the most attention due to high temperatures and reasonable proximity to transmission. CalEnergy drilled the first deep production well in the state with support from BPA, who in turn then paid the developer to drop the project.
- BPA funded an extensive geothermal assessment in the Northwest in the 1980s as a part of its efforts

to invest in geothermal generation. While the assessment yielded useful information for present-day developers, BPA's ultimate goal did not materialize as it stopped its negotiations with geothermal IPPs early this decade.

- Areas in the Cascades also attracted attention, though shallow wells revealed lower temperatures than anticipated, while permitting issues associated with US Forest Service lands and scenic landscapes discouraged further development.
- The Pueblo Valley area in the Alvord KGRA in Harney County offered promise, with Anadarko Petroleum identifying a reservoir at 296 degrees F. The company began PPA negotiations with PGE for a 22-MW binary plant, but PGE pulled out, in part due to environmental concerns about the potential impact on Borax Lake levels.
- A demonstration project using SPS and Ormat binary technology took place near Lakeview in Lake County in 1984 and 1985, after which the developer moved the units to a site in New Mexico.

CURRENT PROJECT DEVELOPMENT EFFORTS

Above 10 MW

The intensity of in-state project development declined in the 1990s but has increased in the current decade. Newberry Crater continues to have the potential to be the largest geothermal plant north of the Geysers. Additional development of plants above 10 MW is occurring at Neal Hot Springs near Ontario and at Crump Geyser by Adel in Lake County.

Newberry Crater

Davenport Power, LLC, a majority owner of and designated operator for the Northwest Geothermal Company, holds leases on 35,000 acres of U.S. Forest Service and BLM land west of the Newberry Volanic National Monument in Deschutes County. The site has experienced much exploration since the 1970s, when it housed the first deep well in the state for geothermal development. Davenport has signed a PPA with PG&E for 120 MW, with Davenport aiming for a late 2009 on-line date for the first 30 MW, then another 30 MW in 2010 and another 60 MW in 2011. The company previously entered into a joint venture with independent power producer (IPP) Vulcan Power for the same site, but terminated the agreement when Vulcan separately bid into a PG&E RFP for the same site.

Further well drilling is required for Davenport to validate previous findings. Observers foresee the need for a deep well (up to 10,000 feet) to characterize the reservoir and determine water availability in the deep "basin and range" magma feature lying underneath the more shallow volcano-based reservoir.

Ormat also holds leases at the site, but has not indicated that the site is a current priority since they have performed little exploration relative to Davenport.

Crump Geyser

The Crump Geyser site near Adel in the Warner Valley of Lake County holds a geothermal exploration well from 1959 that eventually became a continuous erupting geyser, with water that may average 150°C. Nevada Geothermal Power holds leases on 7,200 acres of private land. Initial estimates range from 40 MW to 60 MW over a 20-year period of potential plant operation. Test wells are still required to assess heat and water availability, required depth to access hot water, and avoidance of cold water mixing for a binary plant. Transmission for the site may be a challenge, with only a line owned by Surprise Valley Electric Co-op in the vicinity. The company is currently focusing on a Nevada project for which it entered into a PPA with Nevada Power. It plans to focus more on the Oregon site in the future.

Neal Hot Springs

In 2006, U.S. Geothermal began to purchase leases on 9.6 square miles of private land near Vale. The site was subject to exploration by Chevron Minerals in the 1970s, including a well drilled to almost 3,000 feet. Further analysis by U.S. Geothermal supposedly indicates a reservoir with water up to 356°F. The company still needs to drill test wells to understand the resource potential at the site. It hopes for a 26-MW build-out.

U.S. Geothermal bid the Neal Hot Springs site into an Idaho Power RFP. Idaho Power short-listed the site, as well as portions of the company's Raft River binary project development in Idaho, for further negotiations. The company originally entered into a PPA with Idaho for three units of the Raft River project, but eventually withdrew two units to seek better offers while renegotiating the PPA for the first unit (13 MW). It entered into an MOU with the Eugene Water and Electric Board for the second unit (13 MW).

Warm Springs

As a part of a broader strategy to develop renewable energy resources on its lands, the Confederated Tribes of Warm Springs commissioned a study on geothermal potential on its lands. The study, conducted by McClain Associates with GeothermEx, identified a 95% possibility of a 30- to 50-MW project in the Mount Jefferson area of the reservation. The project would employ binary technology for an average reservoir temperature of 175°C. The tribes are currently developing a biomass power generation plant, and is also planning to develop a wind farm before it begins exploration of geothermal resources. They are seeking federal Bureau of Indian Affairs funds for well drilling.

Below 10 MW

While the projects above are the most commonly publicized efforts in the state, there is the potential for small projects to emerge. Experts are particularly enthusiastic about the development of a manufactured, modular technology that could enable projects below 10 MW. The small-scale binary technology represents the most significant advance in geothermal energy systems in recent times.

Carrier, a subsidiary United Technologies and best known for air conditioners and chillers, has produced an organic rankine cycle binary technology called PureCycle that can use low-temperature resources at a capacity as low as 250 kW. The technology consists of a "reverse refrigerator" applicable to both geothermal and waste heat resources. Hot water enters an evaporator containing a common refrigerant, which boils, vaporizes, and expands through a turbine nozzle to drive a turbine connected to a generator. Cooling water enters a condensor to turn the refrigerant back into liquid, with pumps routing the refrigerant back into the condensor.

In 2006, the company deployed the PureCycle technology at Chena Hot Springs, Alaska, using a 165°F resource and a steady cold water supply. Developers hope for a levelized cost of 7 cents/kWh. One estimate of the system's capital cost ranges from $1,000 to $1,300/kW.

United Technologies' device is not the only one available for commercial use. Barber-Nichols deployed organic rankine cycle systems to a site in Susanville, Calif., in 1985. The device, using water at 200°F, has been in continuous operation without an on-site operator. The company has 750-kW systems available with automated controls. Ormat also manufactures systems for applications at 1 MW and less, and could employ technology used on the Alaska Pipeline and driven by waste heat from pipeline compressors.

The promise of these technologies, and particularly of PureCycle, is the avoidance of extensive piping

investment, modularity for distributed applications, amenability to mass production to reduce unit costs, minimal custom design requirements, and no need for on-site specialists. Instead, it may be possible for local technicians versed in refrigeration technology to respond to potential problems.

Developers are looking at several sites in southern Oregon that could employ the new technology.

Oregon Institute of Technology

OIT in Klamath Falls is assessing the feasibility of a 1.2-MW or higher power project at the campus, with the goal to reduce power costs and to make the campus a "zero-emissions" institution. A full build-out could cost $5 million, while a lower-end project rated at 200 kW could cost $800,000. Some observers think the project could go above 1.2 MW. The targeted steam aquifer may hold a 300 degree F resource at 5,000 feet. School staff are looking at the PureCycle technology for the project. OIT sought $5 million from the state legislature to help fund the project, though it did not receive the funds. It is also considering seeking federal Congressional appropriations for project. It is also considering an RFP for private party financing to take advantage of available state and federal tax incentives.

Lakeview Efforts

The City of Lakeview is examining a couple of opportunities. One site could draw upon two existing wells installed over two years ago to supply hot water to Warner Creek prison north of the town. The city authorized a feasibility study to be completed in November 2007. Reinjection wells already exist, with an available cold water source containing excessive arsenic that precludes it from other uses. One expert estimates potential capacity to be 1 MW, though the city does not have a strong sense of potential yet. The city received a direct Congressional appropriation of $200,000 for the study, and is also seeking funds from the U.S. Department of Energy.

Another site south of Lakeview is the subject of exploration for water temperature and volume for industrial heating uses. Since geothermal generation does not use all hot water available to it, there may be opportunities for combining power generation with such direct uses.

The city hopes to develop the projects on its own using the Oregon business energy tax credit (BETC) and state energy funds.

Paisley

Ranchers and developers in Paisley are conducting a preliminary study of the possibility of a 1-MW project based on a 230°F well dug in the 1920s. Originally, the landowners used the water for irrigation, though pump failure discontinued the practice. Proponents hope the project can yield hot water for a local school to save energy costs as well as generate power. Chevron Energy Solutions is working with the landowners to obtain $33,000 in USDA value-added program funding for the initial study, with possible well drilling to follow, though Chevron is reluctant to invest heavily in test drilling for the small project. The closest transmission is owned by the Surprise Valley Electrical Corporation.

DEVELOPMENT ISSUES

The fact that most current project opportunities in Oregon reside on private lands indicates a key problem for developing the state's geothermal resources: obtaining leases and development rights on the state's public lands. Many of the state's KGRAs exist on lands managed by the U.S. Bureau of Land Management and the U.S. Forest Service.

Geothermal developers need to obtain leases to both the underground mineral rights (for the water and steam) and surface rights (for the plant footprint and access). The land lease is built into the mineral rights lease, and the federal government collects separate royalties on each. (Counties and the federal government each receive 25% of the proceeds while the state receives 50%.) BLM manages lease applications on both their lands and USFS lands, though they must consult with USFS closely for leases on USFS lands. Decisions on leases are based in part on Resource Management Plans (RMPs) adopted by local USFS and BLM offices. RMPs can forbid certain lands for development (e.g., Wilderness Study Areas) and outline key considerations for evaluating lease applications on local lands.

According to a study from the Geothermal Energy Association, in 2003 there were 50 leases awaiting approval on U.S. Forest Service lands, and 70 leases pending on BLM lands. And according to several observers, Oregon's federal agencies have been notorious in their slow processing times compared to other states.

Recent federal policy is changing the lease granting process on federal lands. The 2005 Energy Policy Act (2005 EPAct) directed BLM and USFS to amend RMPs in consideration of geothermal development where high potential exists. The two agencies have also entered into an MOU to ensure that geothermal leases are administered in a timely manner through better inter-agency coordination.

As a result of the 2005 EPAct, both BLM and USFS have initiated programmatic environmental impact statements (EIS) to provide streamlined guidance to regional and local officials to evaluate lease applications. Both agencies are awaiting the results of the programmatic EISs to move more quickly on lease applications. However, the programmatic EIS process itself is slowing down agency efforts. And if BLM's programmatic EIS for wind energy projects is indicative of the final result, the process will do little to avoid site-specific reviews based on NEPA and other considerations.

Perhaps the biggest change in recent time is BLM's move to competitive bidding for new geothermal leases. Previously, such bidding was required only for leases on KGRAs. According to several observers, competitive bidding will stifle efforts by smaller developers to initiate exploration and development on federal lands, out of concern that a larger developer can outbid them for the lease.

Concern over high bid prices appears warranted. In recent auctions of leases in several Western states, prices for leases ranged from approximately $550 per acre in Nevada to $3,000 per acre in California, with the highest prices associated with leases on lands near well-proven reservoirs. Such values dwarf single-digit dollar values for leases for existing sites on private land. Another challenge to project development is the ability of developers to acquire leases next to projects planned by other developers, thereby complicating development and forcing the "incumbent" developer to work with the new leaseholder to develop a project.

It is not known when Oregon leases will be up for auction by BLM, nor how such auctions relate to the programmatic EIS process. Leases, such as those at Newberry Crater, held prior to the new policy are not affected.

Interest in leasing on Oregon lands has grown appreciably in recent years according to Oregon BLM officials. Oregon BLM had often frozen existing leases—essentially stopping the clock related to the 10-year limit for leases (with two five-year extension options). Now the agency is actively monitoring exploration and development activity to ensure that progress is occurring, since lack of progress could result in a termination of a lease.

Other states are moving quickly in issuing leases. According to the Geothermal Energy Association, the Nevada BLM issued 278 leases covering 455,000 acres in the state from 2002 to 2006, compared to just 20

leases for 30,000 acres from 1997 to 2001. While developers are leery about pursuing projects in California due to extensive state enviromental review requirements, a recent BLM auction of California leases yielded $8 million in revenues.

FIRMS

The geothermal industry is the subject of much enthusiasm in a financial sector increasingly interested in investing in clean energy projects based on proven technology. The list below focuses on those firms involved in Oregon, or specializing in products and services that could benefit the Oregon market.

Ormat is a Nevada-based company involved in geothermal energy, waste heat and distributed energy markets. The company manufactures binary power plants of varying sizes, supplying over 900 MW of capacity globally. It is supplying the plant equipment for the Raft River project in Idaho. It operates 318 MW of geothermal plant capacity in the U.S. It also develops power plants in the U.S. and overseas. Ormat has been particularly aggressive in acquiring federal leases through the BLM auction process, and holds leases at Newberry Crater. It is publicly traded on the New York Stock Exchange.

United Technologies is a diversified company that owns Carrier, Pratt and Whitney, Sikorsky, and other subsidiaries. The Carrier division is manufacturer of the PureCycle binary power device, which is sized at 225 kW to 1 MW.

US Geothermal is a publicly-traded geothermal developer whose first project will be the Raft River project in Idaho. It obtained financing from Goldman Sachs for the Raft River project. It is listed on the OTC Bulletin Board and on the Toronto Venture Exchange

Chevron Energy Solutions is owned by Chevron Corporation. It is primarily focused on energy efficiency and power reliability services for large energy customers. It is now investigating involvement in various renewable energy markets, including geothermal.

Nevada Geothermal is an IPP with Vancouver, BC headquarters, with three project sites in Nevada and the Crump Geyser site in Oregon. It is publicly traded on the TSX Venture Exchange and bilaterally through over-the-counter stocks, listed on OTC bulletin board.

Davenport Power, LLC is a private equity firm with leases at Newberry Crater an investments in the oil, natural gas and liquified natural gas sectors.

Raser Technologies is a Utah-based company that is pursuing geothermal projects in the West. It has recently obtained numerous geothermal leases, and has secured PureCycle devices for a 10-MW power plant. It also is involved in technology development for geothermal waste heat applications. It is listed on the New York Stock Exchange.

Barber-Nichols is a Colorado-based company that designs and manufactures blowers, compressors, fans, pumps, turbines, and turbopumps for numerous sectors, including aerospace, defense, and cryogenics. Its organic rankine cycle technology, while used in geothermal applications, is primarily serving the waste heat market.

CONSIDERATIONS FOR ETO

Small binary projects may be poised for sharp market growth, with potential Oregon projects in the mix

When evaluating recent changes in geothermal technology, experts were most excited about advances in small-scale binary technologies, particularly the PureCycle technology from United Technologies, but also noting technology from Barber-Nichols and Ormat. A handful of existing and new projects make up the national portfolio of small binary projects. Oregon alone offers potential due to many low-temperature geothermal applications. Because of the small size of projects, location near load may realize the greatest value from such projects. Load centers in Lake and Klamath counties, as well as smaller loads in Burns and Ontario, may present numerous opportunities for development.

Small projects face high initial cost and risk hurdles

However, the promise of small binary projects is somewhat outweighed by high test well drilling costs relative to ultimate project revenues. Federal deductions may help lessen the risk, though not significantly if the developer is small and/or a public entity. Numerous experts suggested that the ETO could help geothermal development in the state by issuing either grants or loan guarantees for initial drilling. However, the risky nature of such an investment may be a concern to ETO. Rather, the availability of incentives for the output of an eventual project may help incentivize developers to sink funds into drilling with the hope of a strong return.

Co-existing uses can help the prospects of small projects

All of the small project opportunities identified include a goal to generate power and to provide direct use benefits to schools, industrial customers, and institutional customers such as universities. Since geothermal power generation does not make full use of the hot water accessed, it is feasible to consider other uses. Direct uses tend to require lower temperature resources than power generation, making initial investments not wholly dependent on the ultimate operation of a power plant. The promise of dual uses further induces the siting of small projects near loads that can use not only power but also hot water and heating.

For ETO, the possibility of dual uses may encourage examining prospective projects not only by the ETO's renewable energy fund, but also by the energy efficiency fund. It is conceivable that both programs could combine resources to assist the same geothermal project.

Federal lands need to be on the table for all good resources to stand a chance of development

Many of the KGRAs in Oregon are on federal lands, while the project with the largest potential at Newberry Crater is also on federal land. Unfortunately, leasing on federal lands in Oregon is slow, while the focus on competitive bidding may narrow the number of geothermal developers who are willing to develop on federal land. The theoretical supply curve for geothermal power generation in the state is over 1,500 MW according to the Western Governors Association. However, without federal lands in the mix, the existing large-scale (i.e., above 10 MW) project opportunities in the state may represent what is possible for the next 5 years, which is how long it takes to develop a project.

The one upside at the moment is that the high lease prices associated with recent BLM lease auctions could force developers to act quickly to develop on federal lands once they obtain their lease—a significant difference from the historical squatting that numerous leaseholders have done on in-state federal lands.

Neighboring states, and particularly California and Nevada, appear to have plentiful geothermal resources for development, making Oregon's task to attract new projects more challenging

While Oregon seeks its first commercial in-state geothermal power project, both California and Nevada offer greater opportunity for near-term development. A study by GeothermEx identified a minimum of 2,000 MW of gross incremental capacity in California (mostly in the southern Imperial Valley) and 800 MW in Nevada that can be competitive today, taking into consideration other issues such as transmission. The two states' earlier adoption of renewable portfolio standards jump-started in-state geothermal development ahead of other states such as Oregon, Idaho and Arizona.

As utilities in the Northwest seek resources to meet RPSs and attain least-cost generation portfolios, geothermal resources south of Oregon may look particularly attractive. Transmission will be the main constraint that can offer at least a short-term advantage for in-state, large-scale project prospects. However, for at least two projects (Crump Geyser and Neal Hot Springs), the developers are distracted by their existing efforts in neighboring states to move ahead quickly with their Oregon sites.

California offers an attractive market to geothermal developers in Oregon

A resurgence in development activity in the state means that the state may finally see its first commercial geothermal generation project. However, as Davenport's PPA with PG&E for the Newberry Crater site indicates, in-state projects may not translate into in-state consumption of the power. California offers an attractive power market due to high market prices and an RPS that offers contracts up to $93/MWh. With substantial geothermal resource in southern Oregon, and the possibility of new transmission in central and southern Oregon (e.g., PacifiCorp's planned line from eastern Oregon to Captain Jack), the California market should continue to beckon for Oregon's geothermal resources. Any effort to incentivize large-scale (i.e., above 10 MW) projects in the state will have to consider demand south of the state, both when considering what "above-market" costs are, as well as when determining whether and how geothermal power should remain in the state.

FUEL CELLS WITH BIOGAS

INTRODUCTION

Wall Street looked to the fuel cell industry in the late 1990s as a viable, near-term option to standard stationary and mobile energy technologies. Such hopes weakened this decade as expected cost reductions and performance improvements did not occur. Nevertheless, national governments and state agencies continue to support RD&D efforts to integrate fuel cells into the mainstream of energy technologies.

This section briefly examines the key fuel cell technologies for stationary applications, and for applications that use biogas in particular. The discussion then focuses on the state of the fuel cell market for biogas applications, with the goal of determining whether the market is developing or stalled for the purpose of assessing the viability of state incentives to develop the market in Oregon.

TECHNOLOGY

Fuel cells use an electrochemical process to convert hydrogen-rich fuels and oxygen into power, water and useful heat. An anode and cathode surround an electrolyte. Hydrogen entering the system split into electrons and ions on the anode side. The electrons run through a circuit to the cathode, with the current producing electricity. The ions run through the electrolyte, and rejoin the electrons to create heat and water. Fuel cell technology encompasses numerous designs that differ primarily by the type of electrolyte in the design.

Phosphoric acid (PA). The first type of fuel cells to become commercially available, PA cells rely on phosphoric acid as an electrolyte with a platinum catalyst contained in porous carbon electrodes. PA fuel cells operate at relatively low temperatures ranging from 80°C to 392°C depending on specific components and fuels. Because of its lower temperatures and corresponding lower heat rates, PA fuel cells tend to require cleaner gases since the device's temperatures do not eliminate them in the fuel stream. They also require relatively more space to generate the same amount of energy as other types of fuel cells.

Solid oxide (SO). SO fuel cells rely on a non-porous ceramic oxide electrolyte. They operate at high temperatures (800-1000°C) and therefore can tolerate fuels with relatively lower hydrogen content and high sulfur content and carbon monoxide. This feature eliminates the need for a fuel reformer among the balance-of-plant (BOP) components.

Proton exchange membrane (PEM). PEM fuel cells employ a solid polymer membrane electrolyte with porous carbon electrodes. Platinum serves as the catalyst. They operate at lower temperatures (80-150°C) and require less warm-up time than other fuel cells. However, as with PA fuel cells, the lower temperatures expose PEM fuel cells to fuel impurities and carbon monoxide fouling. The lower temperatures also result in heat that is not useful for most end uses.

Molten carbonate (MC). MC fuel cells use a molten carbonate salt electrolyte suspended in ceramic lithium aluminum oxide. MC fuel cells run at very high temperatures (above 650°C) and can tolerate sulfur and carbon monoxide without the need for a fuel reformer. The resulting heat is also amenable to numerous uses.

There are several challenges for fuel cell technology development. The reliance on precious metals as catalysts in PA and PEM fuel cells is expensive and subject to global supply volatility. Manual manufacturing, rather than industrial-scale production, typifies the electrode supply market and results in high unit costs that could drop by 10 times if a shift occurs. BOP components, which can represent half the cost of a complete installed fuel cell system, also offer cost reduction opportunities, particularly for batteries and electric motors, which are the most expensive BOP components.

Overall, key technology concerns include:

Cost. MC and SO fuel cell systems, including BOP, for stationary applications can cost between $12,000/kW and $15,000/kW. Among the 32 fuel cell projects supported by funds from California's Self-Generation Incentive Program, the average cost of the projects was $7,780/W with a low of $4,360/W and a high of $18,000/W. These cost figures compare to $575/kW to $1,225/kW for gas engines configured for combined heat and power (CHP) applications and $700/kW to $2,100/kW for combustion turbines designed for CHP applications.

Lifetime. Compared to other energy options, fuel cells tend to have a low lifetime. According to the International Energy Agency, the target lifetime in stationary applications of both MC and SO fuel cells is approximately 60,000 hours of operation, while PEM's target lifetime is 20,000 hours. Several stationary projects involving biogas have performed for over 50,000 hours. Projects for baseload generation tend to have a lifetime of four to five years.

Fuel treatment. Fuel cells that operate with low temperatures (e.g., PA and PEM) are vulnerable to the presence of impurities such as sulfur and carbon monoxide in the fuel. Based on the City of Portland's recent experience with PA fuel cells at its wastewater treatment plant, the result of PA fuel cells' need for clean gas was the application of expensive carbon charcoal canisters to clean the incoming biogas. (The biogas included sludge-like siloxanes from cosmetic products, sulfur, and high moisture content.) As another layer of complexity attribute to low temperature operations, the PA fuel cells at Portland's plant also required active feeding of the biogas into the system to maintain high pressure and a high heat level in the system.

Some benefits of fuel cells include:

High fuel efficiency. Fuel cells have high fuel-to-energy conversion efficiencies than competing technologies. When using fuel to generate both heat and power, fuel cells can reach efficiencies of 85%, while power-alone applications feature efficiencies of 44% to 50% for MC fuel cells, up to 45% for SO fuel cells, and up to 38% for PA fuel cells. In comparison, gas engines configured for combined heat and power (CHP) applications can offer 35% efficiency, while combustion turbines designed for CHP applications offer approximately 30% efficiency.

Environmental benefits. Fuel cells, particularly in CHP applications, offer some of the cleanest energy options in the market. Emissions can drop to virtually zero depending on the fuel employed (including its carbon and sulfur content), fuel cell technology, and configuration (power only versus CHP). A 2001 study for U.S. EPA and Oak Ridge National Laboratory of various distributed generation options found PA fuel cells (for power only) to be the cleanest distributed baseload option when considering nitrogen oxide, sulfur oxide, carbon dioxide, carbon monoxide, and particulate matter, with the only measured emissions being trace nitrogen oxides (0.000015 lbs/kWh) and carbon dioxide (0.95 lbs/kWh) associated with reforming natural gas.

Due to federal and various state policies that have come into effect over the current decade, emissions of competing technologies have dropped due to cleaner fuels and conversion technologies. However, the trend does not diminish the fuel cell industry's claim of offering the cleanest distributed generation technology in the market.

MARKET CHARACTERIZATION

Projects

The fuel cell market includes numerous applications, including vehicles, mobile applications for power and heat, and stationary applications for power and heat. Different fuel cell manufacturers are focusing on different markets. For the stationary market for biogas fuels, United Technologies' UTC Power (formerly ONSI Fuel Cells) and FuelCell Energy are the two primary manufacturer-developers active in developing projects entailing

biogas.

The two main fuel cell technologies for stationary biogas applications have historically been PA and MC, with the former predominant up to early part of this decade, and the latter gaining dominance thereafter. The superior ability of MC fuel cells to use biogas is the main reason for the switch in fuel cell choice, as the early PA fuel cell projects for biogas showed problems with fuel impurities.

Data on the biogas segment of the fuel cell market comes from Fuel Cells 2000's global project database, which attempts to encompass all operational fuel cell projects in stationary applications. For this report, the search for biogas projects included key words "methane", "biogas", "wastewater", "landfill" and "anaerobic".

Table 3 summarizes all stationary fuel cells projects using biogas worldwide. The market is roughly split between domestic (20 projects totaling 7.3 MW) and overseas (28 projects totaling 6.4 MW) projects.

Table 3. Stationary fuel cell projects fueled by biogas worldwide

Period	Projects	Capacity (kW)	Fuel Cell Type			
			MC	PA	SO	PEM
Through 2000	10	2,200	0	10	0	0
2001-2004	25	6,369	12	8	1	4
2005-2007	6	1,760	4	0	2	0
Planned*	7	3,352	4	0	0	0
Total*	48	13,681	20	18	3	4

* The Fuel Cells 2000 database did not have data on fuel cell type for 3 planned projects.

The data shows that the number of projects that came on-line peaked earlier this decade, with continued efforts to deploy PA fuel cells and the arrival of MC and PEM fuel cells to the biogas market. Currently, interest in MC fuel cells relative to other types is high relative to other fuel cell technologies, though observers are watching the progress of SO fuel cells for stationary applications.

Based on project descriptions in the database as well as on information in U.S. EPA's Landfill Methane Outreach Program (LMOP) database, at least 15 of the projects in the table above were demonstrations of numerous fuel cell technologies that have ended and/or were terminated due to complications.

The biogas segment of the stationary fuel cell market is small when counting both projects and total capacity. The IEA estimates that there are 3,000 stationary fuel cell projects worldwide, with two-thirds consisting of projects up to 10 kW and a third consisting of 10+ kW projects. The biogas segment represents just 2% of the market. On capacity terms, a study by Fuel Cell Today estimated the total stationary market to be approximately 790 MW in 2005. By comparison, the biogas segment represented 10 MW (1%) capacity by the end of 2005. Other fuels such as propane, due to their cleaner composition, are much more prominent in the stationary market.

The biogas market for fuel cells includes several components, in order of prominence among past and existing projects in the Fuel Cells 2000 database: wastewater treatment plants, landfills, agricultural (solid agricultural biomass and animal wastes such as cow and pig manure), breweries, coal methane, and even unused biomass at power plants. Table 4 compares these markets.

Table 4. Types of Biogas-generating industries with fuel cell projects

Type	Projects	% of Total	Capacity (kW)	% of Total

Wastewater	22	46%	7,955	58%
Landfill	12	25%	2,508	18%
Agricultural	3	6%	501	4%
Breweries	5	10%	1,652	12%
Other*	3	6%	800	6%
Unspecified	3	6%	265	2%

- Includes projects that use unused biomass from a power plant, coal mine methane, unspecified industrial biogas.

The presence of wastewater and landfill projects among new projects has been steady over time. The two sectors represented 17 of the 25 projects (68%) installed between 2001 and 2004, and 9 of 13 projects (69%) from 2005 to the present, including planned projects.

Five of the wastewater treatment programs included in the above table resulted from an effort by the New York Power Authority (NYPA) to support fuel cell projects in New York City. The effort stemmed from NYPA's concern about power reliability in the region, as well as interest in distributed generation to increase the city's energy self-sufficiency in light of uncertain transmission adequacy.

The most visible trend in the small intersect between fuel cells and biogas in the brewery sector. Several Japanese breweries (Sapporo, Asahi and Kirin) and Sierra Nevada Brewing in California have adopted fuel cells using anaerobic gas created from wastewater treatment in the breweries. Foster's of Australia is currently planning a project.

Firms

Two firms are active in the biogas segment of the fuel cell market.

UTC Power. Formerly ONSI and based in Connecticut, manufactures PA fuel cells that were most prominent in the late 1990s and early this decade. They were responsible for six wastewater projects (five for NYPA-sponsored projects), with the last one installed in 2004, three landfill projects in the late 1990s, and two brewery projects through 2001, for a total of 14 projects through 2004.

FuelCell Energy. A Connecticut-based manufacturer of MC fuel cells, is associated with six wastewater projects from 2004 onwards, two landfill projects from 2004 onwards, a two brewery projects from 2003 onwards, for a total of 12 projects from 2003 onwards. They are actively looking for other project opportunities in the Northwest and elsewhere.

Overseas, the most number of projects (6) are associated with MTU CFC Solutions, a joint venture between a DaimlerChrysler subsidiary and RWE fuel Cells. They have a license agreement with FuelCell Energy for their MC technology.

Incentives

National and state incentives have been essential for fuel cell projects fueled by biogas:

State Support

- In California, the Self-Generation Incentive Program (SGIP) has supported at least five fuel cell projects fueled by biogas, out of total of 32 fuel cell projects statewide totaling 21 MW. The program is targeted to small- and medium-sized businesses. It offers up to $4.50/W for fuel cells fueled by renewable energy for systems sized 30 kW and larger, which is much higher than the $1/W incentive

for internal combustion engines and gas turbines fueled by renewables and the $1.30/W incentive for microturbines fueled by renewables. The California Energy Commission's Emerging Renewables incentive program focuses on systems 30 kW and less, and offers $3/W rebates to fuel cells. (The only other eligible renewable technology currently is small wind turbines.)

- New York state offers a tax credit for PEM fuel cell systems for power generation, with the credit sized at 20% of total installation costs with a cap of $1,500 per system.
- In Connecticut, the Connecticut Clean Energy Fund offers an On-Site Renewable Distributed Generation program that supports fuel cell projects among others for institutional and commercial customers.

Federal Support

- In the past, both the U.S. Department of Energy (U.S. DOE), U.S. EPA, and even the U.S. Department of Defense have provided grants for fuel cell projects. At least seven projects using biogas have received U.S. DOE, Defense and/or U.S. EPA funds. The projects came on-line up until 2005.
- The 2005 Energy Policy Act includes a 30% investment tax credit for fuel cells, with a ceiling of $1,000/KW for fuel cell projects installed up until December 31, 2007.
- Federal fuel cell RD&D efforts are targeting transportation applications and stationary fuel cell applications using coal mine methane, with the National Energy Technology Laboratory responsible for implementing the latter program. The two programs receive $140 million in funding, with a little more than half going to transportation. There does not appear to be funding specifically for non-coal-mine stationary applications.

CONSIDERATIONS FOR ETO

The biogas market is a low priority to the fuel cell industry, while fuel cells are not a focus for biogas generators.

The fuel cell industry, both globally in the U.S., is most focused on transportation applications as well as stationary applications using natural gas and even biofuels. Only two fuel cell manufacturers appear to be active in looking for opportunities for biogas applications. The U.S. federal government is focused on transportation and stationary applications for coal mine methane, with the latter program offering a possibility that technology advances can benefit other biogas projects.

Conversely, most power and CHP projects using biogas do not use fuel cells. The Fuel Cells 2000 database lists 12 landfill methane projects. In contrast, the U.S. EPA's Landfill Methane Outreach Program's (LMOP's) database lists 533 past and present landfills methane capture projects that have been operational at some point up until the end of 2006. According to the LMOP database, other technologies such as gas turbines and internal combustion engines appear to be the more mainstream generators of choice.

The City of Portland, for example, will install reciprocating generators at its Columbia Wastewater Treatment facility. There are numerous reasons for the choice: (1) lower cost, (2) easier use of the anaerobic waste gas, (3) easier access to qualified O&M technicians, and (4) improved environmental performance of the reciprocating generators due to tightened air emissions standards in California that have influenced overall product design.

New projects will need substantial incentives

Due to fuel cells' higher cost compared to other available technologies, it is not surprising that recent projects have required high up-front funding. The Sierra Nevada Brewing Company's 1-MW fuel cell project in California applied $3.4 million in funding from the SGIP and the federal government to reduce their $7 million price tag for the first five years of the project. It is also telling that California's two relevant rebate programs offer much more per installed Watt for fuel cell projects compared to other available renewable energy

technologies. In spite of the high subsidy level for fuel cells relative to other eligible technologies, by 2006 the SGIP has resulted in 6 MW of fuel cell capacity from all fuels. That capacity represents a little over 3% of the cumulative capacity of projects incentivized by the program.

While there is the potential for significant cost reductions for fuel cells due to cheaper materials and manufacturing processes, such advances are not likely to arrive shortly. Continued RD&D and gradual market expansion will have to play out for fuel cells to become more competitive with other renewable energy and distributed generation technologies.

The brewery industry may offer strong market potential in Oregon

With four operational brewery-based fuel cells projects worldwide, the fuel cell industry has shown that its products can work within breweries. According to the Oregon Brewers Guild, as of 2005 there were 76 breweries in the state, with 38 in the Portland metro area, making the state a big target for marketing and demonstration efforts by fuel cell manufacturers. The caveat is that other energy technologies are available to breweries, though the clean generation properties of fuel cells may make them a strong marketing tool for those breweries interested in incorporating environmental issues in their retail marketing efforts.

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